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Staff Report
Estimated Electric Demand and Supply for Summer 1981 Contiguous United States

May 1981

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U.S. Department of Energy
Assistant Secretary for
Environmental Protection, Safety and Emergency Preparedness
Division of Power Supply and Reliability

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Assistant Secretary for
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Washington, D.C. 20461

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Staff Report on Projected Summer 1981 Electric Load-Supply Situation

SUMMARY

This report summarizes the most recent data available concerning projected electrical peak demands and available power resources for the 1981 summer peak period, as reported by electric utilities in the contiguous United States. The data on loads, purchases and sales, and planned capability, grouped by Regional Council 1/ areas and by Electric Regions 1/ within the Council areas, were obtained from the Reliability Council ERA-411 reports dated April 1, 1981, filed with the Department of Energy. In some instances the data have been revised by staff of the Division of Power Supply and Reliability after discussions with the Councils.

No wide-spread large-scale reliability problems are foreseen for electric power supply this summer, on the basis of the supply and demand projections furnished by the Councils. In some Electric Regions reserve margins could drop to levels considered inadequate for reliable service, if historical generating unit outage levels recur. These regions are

Electric Region	
1	Allegheny Power System
6	Commonwealth Edison Co. Area 2/
12	VACAR
13	CAPCO Group
14	Cincinnati-Dayton Group
28	Northern California-Nevada Area

If projected demands occur and the possible large-scale outages of capacity take place, in these Regions, customers may experience unreliable service 3/ during the summer months. However, the reserves listed for these Regions must be viewed in the context of the capacity available within the corresponding Reliability Council area and the ability of the transmission network to make that capacity available where needed. Careful management of generating and transmission facilities by utility personnel engaged in system operation will be necessary if difficulties are to be minimized.

Data for Electric Regions 2 and 14 in the ECAR area reflect the incorporation of the Columbus and Southern Ohio Electric Co. System (CSO) into the American Electric Power System. CSO was formerly part of the Cincinnati-Columbus-Dayton (CCD) group, which is now designated Cincinnati-Dayton (CD).

Reserve Margins

Each of the Regional Electric Reliability Council areas, and each Electric Region (except 6,27,28), has a projected planned reserve margin that would be satisfactory under normal conditions (Table A). These margins, which do not reflect the effects of capacity purchases and sales transactions between Regions or between Council areas, scheduled maintenance, capacity known to be unavailable, and forced outages, range from 1.2% to 62.8% of the peak demands projected. Table A also shows the possible actual reserve at the time of peak demand, after allowance for scheduled purchases and sales and the capacity that may be unavailable for various reasons; the range is from a negative 15.8% to a positive 27.7%.

1/ See Map on p. iv

2/ The entire MAIN council area could have an actual reserve of 0.3% if historic large-scale capacity unavailability recurs.

3/ "Unreliable" is a qualitative term that includes conditions ranging from minor reductions in voltage for short periods to long-term major voltage reductions, frequency fluctuations, unplanned interruptions to service, and planned rotating interruptions.

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Customer service reliability cannot be directly deduced from Council or Regional reserve margins, since much depends on the weather, daily and weekly variation in load, the interconnections among system, each individual utility's internal transmission, generation facilities and other factors. It is generally agreed, however, that reserve margins of the magnitude shown with an asterisk in Table A would be too low for consistently reliable service. For each of the Electric Regions marked with an asterisk, capacity purchases not now scheduled may be needed. Such capacity appears to be available, for each of these Regions, from systems within their Reliability Council area or from adjoining Council areas.

Table A shows reserves anticipated for the time of the peak non-coincidental demand of each Council area and Electric Region. The peak non-coincidental demand was obtained for each geographic area by summing the peaks projected for each utility in that area. The utility peaks may occur at different times, therefore the area peak tabulated may exceed (probably by no more than some 1 or 2 percent) the actual coincident peak demand. In the case of wide-spread extreme weather conditions, the coincident and non-coincident peaks in any one Council or Electric Region can be very nearly the same. The timing factor also affects the scheduled imports and exports (purchases and sales of capacity) included in the reserve calculations.

Estimates of generating capacity unavailable for service because of scheduled maintenance are as projected in the Reliability Council ERA-411 Reports in most instances. In some cases this capacity has been estimated by staff 1/ on the basis of historic data reported by electric utilities from January 1977 through December 1980. In all cases, the estimates of generating capacity on forced outage and "otherwise unavailable" have been provided by staff. These estimates are based on the outage data reported by electric utilities from January 1977 through December 1980. Generating capacity "otherwise unavailable" includes units that cannot be operated for lack of fuel or because of environmental restrictions; units derated because of cooling water temperature limitations, stack emission limitations, or low quality of fuel; units that cannot run at full capability because of partial forced outages; units whose full capacity cannot be utilized because of transmission limitations.

For the reasons stated, the tabulated data are to be regarded as estimates, not exact numbers that can be verified at a specified time. Following Table A there is detailed discussion of each Reliability Council and Electric Region.

1/ "Staff" in this report refers to the staff of the Division of Power Supply and Reliability.

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Table A
Projected Electric Region Reserves
Summer 1981

Electric Region	Planned Reserve Percent	Possible Actual Reserve[1/] Percent
ECAR		
1. APS	51.4	2.7 *
2. AEP	62.8	23.1
13. CAPCO	29.9	(2.2)*
14. CD	27.3	3.3
15. Kentucky	29.3	27.7
16. Indiana	27.4	11.6
18. MECS	31.6	6.7
Total ECAR	39.0	11.0
MAAC		
5. PJM	35.4	9.9
MAIN		
6. Commonwealth	9.6*	(15.8)*
17. ILLMO	21.5	12.4
19. WUMS	26.7	12.7
Total MAIN	17.5	0.3*
MARCA		
20. MAPP	38.0	28.0
NPCC		
3. NEPOOL	39.7	8.7
4. NYPP	44.2	16.2
Total NPCC	42.3	13.1
SERC		
7. Florida	32.0	12.4
9. Southern	32.6	17.9
11. TVA	43.5	14.4
12. VACAR	24.0	2.9*
Total SERC	32.1	11.0
SPP		
8. MSU/GULF	12.4	9.1
21. MOKAN	17.7	9.3
22. Oklahoma	34.2	19.1
	20.6	12.3
Total Interconnected Councils	32.2	11.2
WSCC		
24. RMPA	47.0	21.3
25. NWPP	45.9	12.1
26. Az-N.M.	49.6	23.6
27. So. Cal.-Nev.	3.9*	11.0
28. No. Cal.-Nev.	1.2*	1.3*
Total WSCC	25.7	11.5
ERCOT		
23. TIS	31.0	17.3

1/ After allowance for net scheduled purchases and sales, scheduled maintenance, forced outages or other unavailable capacity not controllable by the operating electric utility. Possible additional inter-regional capacity purchases and sales are not included.

* Undesireably low reserve.

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Electric Regions in the United States

June 1, 1981 *

* Second revision of July 1, 1979 map.

Reliability Council	
ECAR	-East Central Area Reliability Coordination Agreement
ERCOT	-Electric Reliability Council of Texas
MAAC	-Mid-Atlantic Area Council
MAIN	-Mid-America Interpool Network
MARCA	-Mid-Continent Area Reliability Coordination Agreement
NPCC	-Northeast Power Coordinating Council
SERC	-Southeastern Electric Reliability Council
SPP	-Southwest Power Pool
WSCC	-Western Systems Coordinating Council

Electric Region	Identification
ECAR	
1	Allegheny Power System (APS)
2	American Electric Power System (AEP)
13	Central Area Power Coordination Group (CAPCO)
14	Cincinnati, Dayton Group (CD)
15	Kentucky Group
16	Indiana Group - All Indiana Utilities except I&M Electric Co.
18	Michigan Electric Coordinated Systems (MECS)
ERCOT	
23	Texas Interconnected Systems Group (TIS)
MAAC	
5	Pennsylvania-New Jersey-Maryland Interconnection (PJM)
MAIN	
6	Commonwealth Edison Co.
17	Illinois-Missouri Group (ILLMO)
19	Wisconsin-Upper Michigan Systems Group (WUMS)
MARCA	
20	Mid-Continent Area Power Pool (MAPP)
NPCC	
3	New England Power Pool (NEPOOL)
4	New York Power Pool (NYPP)
7	
9	
11	
12	
SPP	
8+	Middle South Utilities/ Gulf States Utilities Group
21	Missouri-Kansas Group (MOKAN)
22	Oklahoma Group
WSCC	
24	Rocky Mountain Power Pool (RMPP)
25+	Northwest Power Pool (NWPP)
26	Arizona-New Mexico Group
27	Southern California-Nevada Group
28	Northern California-Nevada Group
SERC	
	Florida Coordinating Group (FCG)
	Southern Company Group
	Tennessee Valley Authority Group (TVA)
	Virginia-Carolinas Group (VACAR)

+Region 8 includes former Regions 8 and 10.
Region 25 includes former Regions 25 and 30.

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1. EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT (ECAR)

The East Central Area Reliability Coordination Agreement (ECAR) consists of eighteen member systems in seven power pooling groups which serve all or parts of the states of Michigan, Indiana, Kentucky, Ohio, West Virginia, Virginia, Pennsylvania, Maryland and Tennessee. In addition, the area covered by ECAR includes a number of small systems described as "Liaison Members" of ECAR.

The ECAR noncoincident peak load forecast for the 1981 summer season is 64,346 megawatts (see Table 1.1), a 1.7 percent increase over the actual peak of the 1980 summer. The small increase in load projected for this summer probably reflects the depressed economy of the region, conservation effects and summer weather less extreme than experienced in 1980.

ECAR as a whole is a winter peaking area, although many of its members peak in the summer (usually, each subsequent summer peak exceeds the preceding winter peak and the next winter peak exceeds the preceding summer peak). The diversity allows systems within ECAR to take advantage of seasonal diversity in scheduling maintenance, capacity transfers and in establishing reserve criteria.

Planned capability to meet the 1981 summer peak load forecast is 89,435 megawatts. Included in this total is 500 MW of new coal-fired capacity scheduled for August 1981. 1/ Of the planned generating capability, more than 80 percent is coal-fired, utilizing coal produced primarily within the region from the Appalachian coal fields. Nuclear generating capacity is about 5 percent of installed capability.

The projected actual 1981 summer reserve margins for each ECAR region are given in Table 1.1. The values for scheduled maintenance, full forced outages and other unavailable capability shown in the table were calculated using the historical percent average outages of installed capacity at the time of the seasonal peaks for the period 1977-1980 applied to Line 1 of Table 1.1. 2/ As shown on Table 1.1 for the 1981 summer period, the ECAR region should have adequate reserves (7,092 MW or 11.0 percent) to meet its load responsibility. The reserve margins for individual Electric Regions vary from negative 2.2 percent (CAPCO) to 22.7 percent (Kentucky Group). In each Region except CAPCO the projected reserve margin appears adequate to cover unforeseen contingencies. However, there is enough extra capability within ECAR to supply CAPCO's needs. In addition, the transmission system is adequate to provide energy and capacity transfers among the Regions if unusual problems arise.

The Electric Regions in ECAR are:

1. American Electric Power Group (AEP)
2. Allegheny Electric Power System (APS)
13. Central Area Coordination Group (CAPCO)
14. Cincinnati-Dayton Group (CD)
15. Indiana Group
16. Kentucky Group
18. Michigan Electric Coordinated System (MECS)

1/ See p. 1.3 for a discussion of the effect of this unit.
2/ See Tables 1A.4, 1B.4, 1C.4, 1D.4. These tables are based on utility reports filed on FPC Form 12E-2.

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These Regions are discussed in detail in the following pages. Table 1.1 shows for each Electric Region: planned capability, projected demand, the net of purchases and sales of generating capacity; reserves, the capability that might be unavailable for various reasons, and the resulting reserve.

Kentucky Group

Electric Region 15

The Kentucky Group is projected to have a noncoincident summer peak demand of 6,049 MW. This is 3.5 percent above the actual summer 1980 demand (5,847 MW), but is 2.2 percent less than forecasted in April 1980. The average annual summer load growth was 5.1 percent during the 1977-1980 period.

The planned installed capability is 7,820 MW. This includes the Kentucky Utilities Company's 500 MW Ghent No. 3 Unit scheduled for August 1981. The planned reserve margin is 1,771 MW or 29.3 percent. Net power transfer of 364 MW into the region increases the margin to 2,135 MW or 35.3 percent. Allowance for scheduled maintenance of 63 MW during the period reduces the margin to 2,072 MW or 34.3 percent. Full forced outages during the 1977-1980 summer periods averaged 1.9 percent of installed capability. If the same magnitude of outages were to occur this summer, the reserves would be reduced to 1,923 MW or 31.8 percent. Allowance for other unavailable capability, which averaged 3.2 percent during the 1977-1980 summer periods, reduces the projected actual reserve margin to 1,673 MW or 27.7 percent. This should be more than adequate for coverage of unforeseen contingencies. If Ghent No. 3 is not available in time for the summer peak, the "actual reserve" of line 19 (Table 1.1) would be 1173 MW and the percentage reserve (line 20) would be 19.4%. This magnitude of reserve is considered adequate since it is based on significant allowance for various kinds of outages.

Indiana Group

Electric Region 16

The Indiana Group is projected to have a noncoincident summer peak demand of 9,142 MW. This is 1.8 percent above the actual summer 1980 demand (8,977 MW), but down 6.2 percent from that forecasted in April 1980. The average annual load growth during the 1977-1980 summer periods was 2.5 percent.

The planned installed capability is 11,649 MW. There is no additional major capacity planned for installation during the summer period. The planned reserve margin is 2,507 MW or 27.4 percent. Net power transfer of 635 MW into the region increases the margin to 3,142 MW or 34.4 percent. Allowance for scheduled maintenance of 524 MW reduces the margin to 2,618 MW or 28.6 percent. Full forced outages during the 1977-1980 summer periods averaged 5.8 percent of installed capability. If the same magnitude of outages were to occur this summer, the reserves would be a 1,942 MW or 21.2 percent. Allowance for other unavailable capability, which averaged 7.6 percent during the 1977-1980 summer periods, reduces the projected margin to 1,057 MW or 11.6 percent. This should be sufficient for coverage of unforeseen contingencies.

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Michigan Electric Coordinated Group (MECS)

Electric Region 18

The Michigan Electric Coordinated Group (MECS) is projected to have a noncoincident summer peak demand of 12,087 MW. This is 0.9 percent above the actual summer 1980 demand (11,983 MW) and is down 8.2 percent from that forecasted in April 1980. The decrease in summer peak demand from 1977 to 1980 was equivalent to an average annual decrease of 1.8 percent. The economic condition of the area is greatly dependent upon the auto industry, which has been depressed for the last several years, partly accounting for the decrease in the rate of load growth.

The planned installed capability is 15,912 MW. There is no additional major capacity planned for installation during the summer period. The planned reserve margin is 3,825 MW or 31.6 percent. Net power transfer of 614 MW out of the region reduces the margin to 3,211 MW or 26.6 percent. Allowance for scheduled maintenance of 796 MW during the summer period reduces the reserve margin to 2,415 MW or 20.0 percent. Full forced outages during the 1977-1980 summer periods averaged 4.6 percent of installed capability. If the same magnitude of outages were to occur this summer, the reserves would be reduced to 1,683 MW or 13.9 percent. Allowance for other unavailable capability, which averaged 5.5 percent during the 1977-1980 summer periods, reduces the projected actual reserve margin to 808 MW or 6.7 percent, which appears adequate for coverage of other contingencies.

Allegheny Power System (APS)

Electric Region 1

The Allegheny Power System, Inc. (APS) is the parent company of an integrated electric system comprising the properties of the Monongahela Power Company, the Potomac Edison Company, West Penn Power Company, and their subsidiaries. The three operating companies serve over 1 million customers in southwestern and north central Pennsylvania, the northern portion of West Virginia, the western portion of Maryland and a small portion of northwestern Virginia.

The Allegheny Power System is winter peaking. The peak forecast for the summer 1981 is 4,900 megawatts. This is 3 megawatts less than the actual 1980 summer demand, and 372 MW less than the 1980-81 winter peak. The summer peak demand has shown an average annual growth of 2.5% for the last four years in the APS area.

Planned capability to meet the expected summer peak load is 7,419 megawatts. No major additions are included in the planned capability for the coming summer season. Over 99 percent of current generating capability as shown on Table 1A.2 is vested in coal-fired steam generation. There are no nuclear units installed on the system, and hydroelectric and oil-fired generation are insignificant. Table 1A.3 shows gas and oil use projections for July 1981 and actual data for July 1980. Though oil consumption is comparatively small it is expected to decline.

Capacity out for scheduled maintenance and full forced outages over the past four summer seasons each averaged 9.5% of installed capacity. Other unavailable capability averaged 11.2%. Calculated scheduled maintenance for the coming season, based on a four year average is 704 MW, shown in Table 1.1, line 9. The four-year average full forced outage of 704 MW is included in Table 1.1 line 13, as representative of the forced outage that could occur for APS. Other unavailable capability

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of 831 MW is included on Table 1.1 line 17. There has been a substantial increase in the APS forced outage rate during the period 1977-1979 as a result of persistent and lengthy outages of the larger units on the system. However, in 1980, for the first time in four years, APS experienced no forced outages at the time of their summer peak.

Pleasants No. 2 unit, installed in December 1980 is scheduled to be uprated 61 MW in July.

Scheduled contract purchases during the summer period include a firm 300-megawatt diversity delivery to Virginia Electric and Power Company (VEPCO) and a nonfirm purchase of 153 megawatts from the Ohio Valley Electric Company, resulting in a net export of 147 MW. The 300 megawatts to VEPCO is to be returned during the winter peak period.

As indicated in Table 1.1, for summer 1981 the APS Region's planned reserves of 51.4 percent, and the possible available reserves of 19.7 percent, respectively, are adequate. The actual reserves could be 133 MW or 2.7%, if the previous high incidence of forced outages as occurred in 1978 and 1979 is again experienced. This reserve level, after consideration of all possible outages, is marginal.

For the 1981 summer season, no major transmission lines are scheduled for completion. The transmission system is adequate to cover load commitments for the period, with no areas posing stability problems.

American Electric Power Group (AEP)

Electric Region 2

The American Electric Power System Region includes American Electric Power Company, Buckeye Power, Inc., Ohio Valley Electric Corporation, Columbus & Southern Ohio Electric Company, and the Richmond Power and Light Municipal. The American Electric Power Company is an electric utility holding company comprising seven wholly owned subsidiary companies operating in parts of seven states; Ohio, Indiana, Michigan, West Virginia, Virginia, Kentucky and Tennessee. This includes the recently acquired properties of Columbus and Southern. This report reflects forecast figures for C&SOE Co. and the previous regional figures have been adjusted for C&SOE Co. for comparison purposes. Buckeye Power, Inc. is essentially an association of all the electric cooperatives in the State of Ohio. The Ohio Valley Electric Corporation (OVEC) was originally formed by a consortium of ten electric companies in ECAR to provide electric power to the Department of Energy's Uranium Enrichment Plant in Portsmouth, Ohio. The Richmond, Ohio Municipal system has been included in this report for the first time.

The AEP region is a winter peaking area. The peak forecast for the summer 1981 is 15,196 megawatts. This is a 1.7 percent increase over the actual peak of the previous summer, and a decline of 3.3 percent from the summer peak of 1979. Peaks in this region have fluctuated because of weather conditions, as would be expected, and also because of the varying load requirements of DOE's Portsmouth nuclear processing plant. The plant's load requirements are normally supplied by Ohio Valley Electric Corp. (OVEC), a consortium of electric utilities who are obligated to furnish whatever generating capacity is needed beyond what is available from the

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two OVEC plants. AEP, a member of the consortium, is a major contributor when additional power is required.

Planned capability to meet the coming summer peak load is 24,733 megawatts. No major capacity additions are included in the planned capability for this season. Table 1B.2 indicates actual and projected generation for July 1980 and July 1981 respectively. Nuclear generation is expected to increase as a percentage of total generation. Oil consumption is limited to startup and no major plants used heavy oil in 1980.

Almost 88 percent of the current capability in the region is coal-fired steam capacity, and 8.5 percent is nuclear. AEP's large planned reserves in coal-fired generation, and a strong transmission system, are used to advantage by selling capacity to other utilities in the region.

Capacity out for scheduled maintenance over the past four summer seasons averaged 8.1%; full forced outages and unavailable capability averaged 4.7% and 5.7% respectively. Calculated forced outage for the coming summer season (percentage-based) is 1,158 megawatts; this is shown in Table 1.1, line 13, as representative of the probable forced outage. The unavailable capability has been included in Table 1.1 line 17.

The AEP group has no contracts with systems in Reliability Councils adjoining ECAR for scheduled transfers of power. However, there are many firm and nonfirm contracts with other companies in ECAR. As shown in Table 1.1 for the summer the AEP group planned reserves are 62.8%. Actual reserves after possible unit outages for the Region could drop to 23.1%. This should be sufficient to meet the load responsibility of the AEP system, and in addition meet deficits in other ECAR systems should they develop.

A critical transmission line, the 765 Kv Gavin-Culloden line, which is needed to carry the output of the Gavin-Mountaineer Generating Complex (3900 MW) to various load centers on the AEP system, is delayed as a result of litigation. It is expected to become operational in December 1982. No new major transmission lines are scheduled for service during the summer peak load season.

Cincinnati-Dayton Group (CD)

Electric Region 14

This region includes the Cincinnati Gas & Electric Co., the Dayton Power and Light Company and the municipal system of Hamilton, Ohio. Hamilton has not reported regularly but is included in the present data. Columbus & Southern Ohio Electric Company, formerly a member of this group and part of the Electric Region for operating purposes, has been purchased by American Electric Power System and is now included in the AEP area, instead of Electric Region 14. Historical data used in this report has been adjusted to reflect this change.

The CD group is summer peaking. The peak forecast for the summer 1981 is 5,352 megawatts. This represents a growth of 1.7 percent above the previous summer season, and 7.6 percent above the peak of 1979.

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Planned capability to meet the coming summer peak load is 6,813 megawatts. East Bend #2, a 600 MW coal fired steam unit became commercial in March 1981 and will be available for the summer season. The unit is jointly owned by Cincinnati Gas & Electric and Dayton Power & Light. Zimmer No. 1, the first nuclear unit to be installed in the Region, originally scheduled for January 1981, has been rescheduled for June 1982 and is not included as available for the peak period of 1981.

Ninety-nine percent of the current capability of the area is coal-fired capacity; the remainder is oil and gas. There is only one small hydro station, and no nuclear facilities, in this Electric Region, at this time.

Table 1D.3 shows gas and oil projections for July 1981 and actual data for July 1980. All of the oil used is light oil for start-up. The forecast increase in oil is due to the installation of East Bend #2.

Capacity out for scheduled maintenance over the past four summer seasons averaged 8.1%, full forced outages averaged 4.7% and unavailable capacity averaged 3.5% as shown on Table 1D.4. Calculated scheduled maintenance for the coming summer season based on this average is 552 megawatts. The four-year average full forced outage is included in Table 1.1 line 13, as representative of the forced outage that could occur for CD. Other unavailable capability is included on Table 1.1 line 17 (557 MW).

The CD Region has no firm contracts for scheduled transfers of power with systems in Reliability Councils adjoining ECAR; however, some intra-regional contracts exist.

As indicated in Table 1.1 for the summer 1981, the CD Region's planned reserves of 27.3 percent and possible available reserves of 14.1 percent, respectively, appear adequate for the coming season. If the other unavailable capability is as forecasted, the actual reserves would be 3.3 percent. This reserve would probably be sufficient to avoid major problems.

For the 1981 summer season, no major transmission lines are scheduled for completion. The transmission system is adequate to cover load commitments for the period, with no stability problems.

Central Area Power Coordination Group (CAPCO)

Electric Region 13

This region includes the Central Area Power Coordination Group (CAPCO) and the Cleveland and Bryan Municipal Systems. CAPCO consists of five investor-owned electric utilities providing service in northern Ohio and western Pennsylvania. The systems are: The Cleveland Electric Illuminating Company, Duquesne Light Company, Ohio Edison Company, Pennsyulvania Power Company, and the Toledo Edison Company.

CAPCO is summer peaking and the peak forecasted for the summer 1981 is 11,620 megawatts. This represents a 2.9 percent increase over the actual peak of the previous summer, and an 8.7 percent increase over the peak of the summer two years ago. The 1980 summer peak was unusually high due to extremely hot weather.

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Table 1C.2 indicates actual generation for July 1980 and projected July 1981 data. There is a sharp change in the nuclear generation due to the Beaver Valley units going on line and the increased generation at Davis Besse. These units were not operating at full capacity in July 1980.

Approximately 77 percent of the current capability is coal-fired steam generation, 12 percent is nuclear fueled, 9 percent oil-fired and 2 percent is pumped storage.

Table 1C.3 shows gas and oil projections for July 1981 and actual data for July 1980. The forecasted reduction of 77.9% in oil use, coupled with the forecasted 92.8% reduction in oil-based energy generation, indicates that much of the reduction will in base-load oil generation. Base load units are more efficient than peaking units, therefore it appears that the remaining oil use (22.1% of the July 1980 quantity) will be utilized mainly in peaking units to provide some 7.2% of the July 1980 generation. The reduction in oil-fired base load generation will be counterbalanced by the large increase expected in nuclear generation.

Capacity out for scheduled maintenance over the past four summer seasons averaged 6.8% of installed capacity and full forced outages averaged 8.7%. Unavailable capacity averaged 11.9%. Calculated scheduled maintenance for the coming summer season based on this percentage is 1,025 megawatts. The four-year average of full forced outages is included in Table 1.1, line 13, as representative of the forced outages that could occur for the CAPCO area. Unavailable capability is included on Table 1.1 line 17. The CAPCO region has a firm contract for 300 MW of scheduled power transfer to MAAC for GPU. In addition, some intra-regional interchange contracts exist.

As indicated in Table 1.1 for summer 1981, the CAPCO Region's planned reserves of 29.9 percent and the possible available reserves of 13.2 percent, respectively, appear adequate. If. however, the historical high incidence of scheduled, forced outage other unavailable capability continues, the actual reserves would be reduced to a negative 259 megawatts or (2.2) percent. This would be inadequate for reliable service.

There are delays in the completion of two major lines that could pose problems during the 1981 summer season. The Mansfield-Juniper 345 Kv line, an extension of the Mansfield-Hanna 345 Kv Line, which was originally scheduled for service in 1977, is under litigation and an 8.7-mile section is still to be completed. The double circuit 345 Kv Juniper-Harding line was originally scheduled for December 1973; while a major portion is completed, a part of the line has been delayed by litigation and by the need to obtain a permit from the National Park Service. The projected in-service date of the Juniper-Harding line is now April 1984.

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TABLE 1.1

EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT (ECAR)
TABULATION OF ESTIMATED LOAD AND SUPPLY FOR SUMMER 1981 PEAK PERIOD

	ALLEGHENY POWER SYSTEM (APS)	AMERICAN ELECTRIC POWER GROUP (AEP) /3/	CENTRAL AREA POWER COORDINATION GROUP (CAPCO)	CINCINNATI DAYTON GROUP (CD) /3/	KENTUCKY GROUP	INDIANA GROUP	MICHIGAN ELECTRIC COORDINATED GROUP (MECS)	TOTAL ECAR /4/ REGION
1. PLANNED CAPABILITY (MW)	7419	24733	15089	6813	7820 5/	11649	15912	89435 5/
2. PEAK DEMAND (MW)	4900	15196	11620	5352	6049	9142	12087	64346
3. PLANNED RESERVES (MW) (1-2)	2519	9537	3469	1461	1771	2507	3825	25089
4. PLANNED RESERVES (%) (3/2) X 100	51.4	62.8	29.9	27.3	29.3	27.4	31.6	39.0
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	-147	-1474	401	166	364	635	-614	-669
6. TOTAL CAPABILITY (MW) (1+5)	7272	23259	15490	6979	8184	12284	15298	88766
7. TOTAL RESERVES (MW) (6-2)	2372	8063	3870	1627	2135	3142	3211	24420
8. TOTAL RESERVES (%) (7/2) X 100	48.4	53.1	33.3	30.4	35.3	34.4	26.6	38.0
9. SCHEDULED MAINTENANCE (MW) /1/	704	1996	1025	552	63	524	796	5660
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	6568	21263	14465	6427	8121	11760	14502	83106
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	1668	6067	2845	1075	2072	2618	2415	18760
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	34.0	39.9	24.5	20.1	34.3	28.6	20.0	29.2
13. FULL FORCED OUTAGES (MW) /1/	704	1158	1311	320	149	676	732	5050
14. CAPABILITY AFTER FULL FORCED OUTAGES (MW) (10-13)	5864	20105	13154	6107	7972	11084	13770	78056
15. RESERVES AFTER FULL FORCED OUTAGES (MW) (14-2)	964	4909	1534	755	1923	1942	1683	13710
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2) X 100	19.7	32.3	13.2	14.1	31.8	21.2	13.9	21.3
17. OTHER UNAVAILABLE CAPABILITY (MW) /1/ /2/	831	1405	1793	379	250	885	875	6618
18. ACTUAL CAPABILITY (MW) (14-17)	5033	18700	11361	5528	7722	10199	12895	71438
19. ACTUAL RESERVES (MW) (18-2)	133	3504	-259	176	1673	1057	808	7092
20. ACTUAL RESERVES (%) (19/2) X 100	2.7	23.1	-2.2	3.3	27.7	11.6	6.7	11.0

/1/ SCHEDULED MAINTENANCE, OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER PEAKS BEGINNING WITH THE 1977 SUMMER. DATA OBTAINED FROM FPC FORM-12E2.

/2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

/3/ COLUMBUS & SOUTHERN OHIO ELECTRIC COMPANY IS NOW INCLUDED IN THE AEP GROUP.

/4/ ALL LIAISON MEMBER SYSTEMS HAVE BEEN INCORPORATED WITH APPROPRIATE BULK POWER MEMBER SYSTEMS FOR THE PURPOSE OF THIS REPORT.

/5/ INCLUDES GHENT NO. 3, 500 MW, SCHEDULED FOR AUGUST 1981.

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Table 1A.2
ACTUAL AND PROJECTED GENERATION BY FUEL TYPE
ALLEGHENY POWER SYSTEM (APS)

FUEL TYPE	ACTUAL JULY 1980 GENERATION (MWH)	% OF TOTAL	PROJECTED JULY 1981 GENERATION (MWH)	% OF TOTAL
Hydro	11,951	0.4	10,200	0.4
Coal	2,775,013	98.8	2,842,900	99.3
Gas	1,201	0.0	-	-
Oil	21,413	0.8	9,800	0.3
Nuclear	-	-	-	-
Pump Storage (Net)	-	-	-	-
Total	2,809,578	100.0	2,862,900	100.0

SOURCE: ACTUAL DATA -FERC FORM 4
PROJECTED DATA - ERA FORM 160

Table 1A.3
GAS AND OIL USE PROJECTION FOR JULY 1981
VS
ACTUAL GAS AND OIL USE FOR JULY 1980
ALLEGHENY POWER SYSTEM (APS)

FUEL TYPE	JUL. 1981 PROJECTION	JUL. 1980 ACTUAL	PERCENT 7-81/7-80
Gas (MCF)	-	13	-
Oil (BBLS)	16,330	46,165	35.4

SOURCE: ACTUAL DATA - FERC FORM 4
PROJECTED DATA - ERA FORM 160

Table 1A.4
AVERAGE GENERATING CAPACITY UNAVAILABLE AT THE TIME OF THE
SUMMER SYSTEM PEAK DEMAND 1977, 1978, 1979,1980
ALLEGHENY POWER SYSTEM APS

MONTH-YEAR	SCHEDULED MAINTENANCE (MW)	SCHEDULED MAINTENANCE % OF INSTALL CAPACITY	FULL FORCED OUTAGES (MW)	FULL FORCED OUTAGES % OF INSTALL CAPACITY	OTHER UNAVAILABLE CAPACITY (MW)	OTHER UNAVAILABLE CAPACITY % OF INSTALL CAPACITY
Aug. 1977	596	9.2	315	4.8	632	9.7
Aug. 1978	500	7.7	971	14.9	714	11.0
Aug. 1979	669	9.5	1280	18.1	554	7.8
July 1980	816	11.5	0	0	1140	16.1
4-Yr. Average		9.5		9.5		11.2

SOURCE: FPC FORM 12E-2

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Table 1B.2
ACTUAL AND PROJECTED GENERATION BY FUEL TYPE
AMERICAN ELECTRIC POWER GROUP (AEP)

FUEL TYPE	ACTUAL JULY 1980 GENERATION (MWH)	% OF TOTAL	PROJECTED JULY 1981 GENERATION (MWH) *	% OF TOTAL
Hydro	39,640	0.3	51,000	0.4
Coal	12,654,141	96.1	11,530,574	90.9
Gas	2,298	0.0	-	-
Oil	44,828	0.3	-	-
Nuclear	427,116	3.2	1,121,000	8.8
Pump Storage (Net)	NA	NA	(16,000)	(0.1)
Total	13,168,023	100.0	12,686,574	100.0

*BUCKEYE POWER INC. DATA ARE NOT REPORTED IN ERA FORM 160

SOURCE: ACTUAL DATA - FERC FORM 4
PROJECTED DATA - ERA FORM 160

Table 1B.3
GAS AND OIL USE PROJECTION FOR JULY 1981
VS
ACTUAL GAS AND OIL USE FOR JULY 1980
AMERICAN ELECTRIC POWER GROUP (AEP)

FUEL TYPE	JUL. 1981 PROJECTION	JUL. 1980 ACTUAL	PERCENT 7-81/7-80
Gas (MCF)	-	39	-
Oil (BBLS)	64,000	75,365	84.9

SOURCE: ACTUAL DATA - FERC FORM 4
PROJECTED DATA - ERA FORM 160

Table 1B.4
AVERAGE GENERATING CAPACITY UNAVAILABLE AT THE TIME OF THE
SUMMER SYSTEM PEAK DEMAND 1977, 1978, 1979, 1980
AMERICAN ELECTRIC POWER GROUP (AEP)

MONTH-YEAR	SCHEDULED MAINTENANCE		FULL FORCED OUTAGES		OTHER UNAVAILABLE CAPACITY	
	(MW)	% OF INSTALL CAPACITY	(MW)	% OF INSTALL CAPACITY	(MW)	% OF INSTALL CAPACITY
July 1977	1335	5.9	1090	4.9	1022	4.5
July 1978	1636	6.5	1910	7.6	1787	7.1
Aug. 1979	2260	9.2	655	2.7	1373	5.6
July 1980	2631	10.7	850	3.4	1368	5.5
4-Yr. Average		8.1		4.7		5.7

SOURCE: FPC FORM 12E-2

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Table 1C.2
ACTUAL AND PROJECTED GENERATION BY FUEL TYPE
CENTRAL AREA POWER COORDINATION GROUP (CAPCO)

FUEL TYPE	ACTUAL JULY 1980 GENERATION (MWH)	% OF TOTAL	PROJECTED JULY 1981 GENERATION (MWH)	% OF TOTAL
Hydro	-	-	-	-
Coal	4,438,017	97.6	4,545,798	84.0
Gas	917	0.0	-	-
Oil	72,779	1.6	5,208	0.1
Nuclear	35,164	0.8	860,743	15.9
Pump Storage (Net)	-	-	-	-
TOTAL	4,546,877	100.0	5,411,749	100.0

SOURCE: ACTUAL DATA - FERC FORM 4
PROJECTED DATA - ERA FORM 160

Table 1C.3
GAS AND OIL USE PROJECTION FOR JULY 1981
VS
ACTUAL GAS AND OIL USE FOR JULY 1980
CENTRAL AREA POWER COORDINATION GROUP (CAPCO)

FUEL TYPE	JUL. 1981 PROJECTION	JUL. 1980 ACTUAL	PERCENT 7-81/7-80
Gas (MCF)	-	18	-
Oil (BBLS)	31,267	141,589	22.1

SOURCE: ACTUAL DATA - FERC FORM 4
PROJECTED DATA - ERA FORM 160

Table 1C.4
AVERAGE GENERATING CAPACITY UNAVAILABLE AT THE TIME OF THE
SUMMER SYSTEM PEAK DEMAND 1977, 1978, 1979, 1980
CENTRAL AREA POWER COORDINATION GROUP (CAPCO)

MONTH-YEAR	SCHEDULED MAINTENANCE		FULL FORCED OUTAGES		OTHER UNAVAILABLE CAPACITY	
	(MW)	% OF INSTALL CAPACITY	(MW)	% OF INSTALL CAPACITY	(MW)	% OF INSTALL CAPACITY
July 1977	414	3.0	863	6.2	1138	8.2
July 1978	1005	6.4	1571	10.0	2172	13.9
July 1979	830	5.2	1631	10.3	2177	13.8
July 1980	2034	12.5	1360	8.4	1879	11.6
4-YR. AVERAGE		6.8		8.7		11.9

SOURCE: FPC FORM 12E-2

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Table 1D.2
ACTUAL AND PROJECTED GENERATION BY FUEL TYPE
CINCINNATI-DAYTON GROUP (CD)

FUEL TYPE	ACTUAL JULY 1980 GENERATION (MWH)	% OF TOTAL	PROJECTED JULY 1981 GENERATION (MWH)	% OF TOTAL
Hydro	757	0.0	600	0.0
Coal	2,486,575	97.7	2,343,750	98.4
Gas	16,463	0.6	6,600	0.3
Oil	42,148	1.7	31,035	1.3
Nuclear	-	-	-	-
Pump Storage (Net)	-	-	-	-
TOTAL	2,545,943	100.0	2,381,985	100.0

SOURCE: ACTUAL DATA - FERC FORM 4
PROJECTED DATA - ERA FORM 160

Table 1D.3
GAS AND OIL USE PROJECTION FOR JULY 1981
VS
ACTUAL GAS AND OIL USE FOR JULY 1980
CINCINNATI-DAYTON GROUP (CD)

FUEL TYPE	JUL. 1981 PROJECTION	JUL. 1980 ACTUAL	PERCENT 7-81/7-80
Gas (MCF)	149	259	57.5
Oil (BBLS)	94,097	80,134	117.4

SOURCE: ACTUAL DATA - FERC FORM 4
PROJECTED DATA - ERA FORM 160

Table 1D.4
AVERAGE GENERATING CAPACITY UNAVAILABLE AT THE TIME OF THE
SUMMER SYSTEM PEAK DEMAND 1977, 1978, 1979, 1980
CINCINNATI-DAYTON GROUP (CD)

MONTH-YEAR	SCHEDULED MAINTENANCE		FULL FORCED OUTAGES		OTHER UNAVAILABLE CAPACITY	
	(MW)	% OF INSTALL CAPACITY	(MW)	% OF INSTALL CAPACITY	(MW)	% OF INSTALL CAPACITY
July 1977	432	7.2	123	2.0	417	6.9
July 1978	962	14.6	124	1.9	589	9.0
Aug. 1979	589	9.0	389	5.9	731	11.1
July 1980	104	1.6	602	9.1	468	7.1
4-YR. AVERAGE		8.1		4.7		8.5

SOURCE: FPC FORM 12E-2

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2. Electric Reliability Council of Texas (ERCOT)
Electric Region 23

The members of the Electric Reliability Council of Texas (ERCOT) supply electric power within the State of Texas only and do not as yet operate in synchronism with any of the other eight Reliability Council areas. The entire ERCOT area is included in the Texas Interconnected Systems Group (TIS) (Electric Region 23). The area is internally divided into the North and South Texas areas for planning and operating purposes, and each area is monitored by a security center. There are also seven control centers in the South Texas area and three in the North Texas area.

ERCOT usually experiences its peak electric load in July or August during periods of prolonged hot dry weather. Its winter peak occurs in December or January and is approximately 75 percent of the summer peak load. The 1981 non-coincident summer peak demand for Region 23 is projected by ERCOT to be 32,825 MW, which is an increase of approximately 2.5 percent over the actual non-coincident 1980 peak. The increase from 1979 to 1980 was 12.6 percent. The large actual load growth of 12.6 percent was the result of two consecutive summers of abnormal weather conditions; 1979 was below average and 1980 was extremely hot and dry. The estimated peak demand of 32,825 MW is based on average weather conditions, but according to long range weather predictions the 1981 summer period will again be hot and dry. Based on these predictions Region 23 could experience another year of above average load growth. The predicted Actual Reserve for the 1981 summer peak period is 5,677 MW or 17.3 percent of peak demand (see Table 2.1). If Region 23 experienced a load growth in 1981 approaching the 1979-80 growth, actual reserves could drop to 2,107 MW or 5.8 percent.

The existing high voltage transmission system is at the 345 kV level and extends east to west in the North Texas portion of the area and north to south between the North and South Texas areas. The 345 kV system between North and South Texas was constructed primarily for reliability purposes and until recently was not used for economy energy transactions.

Texas is presently isolated electrically from other electric regions in the nation. The Central & South West Corporation (CSW) has petitioned the Federal Energy Regulatory Commission (FERC) to order ERCOT to interconnect with the Southwest Power Pool (SPP). As a result of this petition, systems in ERCOT and SPP have signed an interconnection agreement which has not yet been approved by FERC. The agreement calls for construction of two direct current transmission lines, one in East Texas and one from Oklahoma into West Texas. Consummation of this interconnection could have some effect on the load and supply situation in future years. At the present time the legal proceedings are still within FERC.

The data in Table 2.1 was derived from information reported by ERCOT in its ERA-411 Report submitted April 1, 1981.* Full forced outages and other unavailable capability were calculated by DOE based upon 1977-80 historical averages at the time of the summer peaks. Information to calculate these averages was obtained from FPC Form 12E-2 reports filed by the ERCOT systems. These figures are 3.9 percent and 5.9 percent, respectively. Scheduled maintenance is used as projected by ERCOT since the systems have firm plans for removing capacity for maintenance during the upcoming summer peak period. The projected actual reserve margin for the 1981 summer peak period is 17.3 percent. This margin includes the effect of 4,660 MW unavailable (10.8 percent of planned capability) which consists of scheduled maintenance, full forced outages and other unavailable capability.

ERCOT is highly dependent upon natural gas for generation. There is installed or proposed for operation a total of 32,459 MW of gas-fired generation for the summer of 1981, which amounts to 75 percent of total capability in Region 23. This capability is considered dependable since cutbacks in natural gas supplies generally only occur during the winter months due to home heating priority. Fuel supplies appear more than adequate for this summer. The 230 MW of hydroelectric capacity and the 102 MW of oil-fired capacity are not expected to present fuel supply problems.

* The Planned Capability on Line 1 of Table 2.1 is 19 MW less than the Net Dependable Capability listed for the summer of 1981 on Line 1 of Item 3-A in ERCOT's report. The capability in Table 2.1 was obtained by adding to the existing capability from ERCOT's Item 2-A the changes scheduled to occur before the 1981 summer peak period as shown in Item 2-B.

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Although presently isolated, ERCOT shows net imports of 150 MW (Line 5 of Table 2.1). This is due to imports from non-member systems within the ERCOT region and from systems outside of the region that supply a part of the West Texas Utilities Co. system, located within the ERCOT area but not connected to the ERCOT (Texas Interconnected) system. The summer load-supply situation appears to be satisfactory. Fuel should be available in sufficient quantity to supply all energy requirements.

TABLE 2.1

ELECTRIC RELIABILITY COUNCIL OF TEXAS (ERCOT)

TABULATION OF ESTIMATED LOAD AND SUPPLY FOR SUMMER 1981 PEAK PERIOD

MW OR PERCENT	TEXAS INTERCONNECTED SYSTEMS GROUP (TIS)
1. PLANNED CAPABILITY	43012
2. PEAK DEMAND	32825
3. PLANNED RESERVES (1-2)	10187
4. PLANNED RESERVES (%) (3/2)X100	31.0
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	150
6. TOTAL CAPABILITY (1+5)	43162
7. TOTAL RESERVES (6-2)	10337
8. TOTAL RESERVES (%) (7/2)X100	31.5
9. SCHEDULED MAINTENANCE	445
10. CAPABILITY AFTER MAINTENANCE (6-9)	42717
11. RESERVES AFTER MAINTENANCE (10-2)	9892
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	30.1
13. FULL FORCED OUTAGES 1/	1677
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	41040
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	8215
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	25.0
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	2538
18. ACTUAL CAPABILITY (14-17)	38502
19. ACTUAL RESERVES (18-2)	5677
20. ACTUAL RESERVES (%) (19/2)X100	17.3

1/ OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER.
DATA OBTAINED FROM FPC FORM-12E2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

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3. Mid-Atlantic Area Coordination Council (MAAC)
Pennsylvania-New Jersey-Maryland Interconnection (PJM)
Electric Region 5

The Mid-Atlantic Area Coordination Council (MAAC) is operated as a single system under the Pennsylvania-New Jersey-Maryland Interconnection (PJM) pooling agreement. PJM coordinates the bulk power supply of its eleven investor-owned utility members, and through associate membership, the municipals, electric cooperatives, and small investor-owned electric systems, in the MAAC region. The MAAC region includes all of Delaware and the District of Columbia, major portions of Pennsylvania, New Jersey and Maryland, and a small portion of Virginia. There are no Electric Region subdivisions of MAAC.

The PJM peak load forecast (including interruptible load) for summer 1981 is 34,102 megawatts, which includes the Allegheny Cooperative Load of 107 MW (See Table 3.1). This is a 2.3% decrease below the actual peak (computed on the same basis) of the previous summer. The 1980 peak was almost 2,800 megawatts higher than the 1979 summer peak, due primarily to sustained unusually hot weather. More normal weather is reflected in the lower peak forecast for summer 1981. As a result of heavy air conditioning loads, PJM is a weather-sensitive summer peaking area; the summer peak can occur in any summer month.

Planned capability to meet the 1981 summer peak load forecast is 46,176 megawatts. Included in the planned capability are TMI 1 and TMI 2, 1,114 megawatts of new capacity and retirements of 40 megawatts. Salem No. 2, a 1,114 megawatt nuclear unit orginally scheduled for initial operation in January, has been delayed until April 1981 and has been included as being available for the summer season. TMI 1 and TMI 2 are included in Line 17 of Table 3.1 with other unavailable capability and therefore are excluded from the actual reserves of Line 20.

Coal-fired generation represented 58% of the total energy produced in July 1980 while oil and gas-fired generation combined represented 23%, nuclear fueled capacity 19% and hydro generation was less than 1%. Table 3.2 indicates actual July 1980 and projected July 1981 generation by fuel type based on ERA-Form 160. Table 3.3 provides fuel-use projections for oil and gas for July 1981 and actual use for July 1980. The rapid growth in the peak requirements between summer 1979 and summer 1980 may indicate a need for additional peaking capacity in the immediate future. If in 1981 the area experiences the prolonged heatstorm that it experienced in 1980, shortfalls in peaking capacity may be evident. The loss of the Three Mile Island nuclear units has increased PJM dependence on older, higher cost capacity, and has made it economically advantageous to import short-term firm energy from neighboring pools.

PJM has scheduled for its peak demand period firm receipts from NPCC: Ontario Hydro-200 MW, Power Authority of the State of N.Y.-107MW, and from ECAR: American Electric Power (thru Cleveland Electric Illuminating Company) 300 MW. The GPU Lake Erie Technical Data Study states that a letter of intent was signed on 2/10/81 for 254MW of additional capacity from Ontario Hydro thru the Michigan pool and CAPCO to GPU, although no firm contract has been executed. This import has not been included as a firm receipt during the summer peak in Table 3.1. The roundabout route proposed for this purchase is due to lack of sufficient transmission capacity on the more direct route from Ontario Hydro through New York.

Table 3.4 shows the average generating capacity unavailable at the time of the summer system peak demand for the past four summers as a percent of installed capacity, and the four-year average. The four-year average scheduled maintenance rate of 3.0% is less than the 4.4% forecasted by PJM for summer 1981. The PJM forecast was the one used for developing Table 3.1. The four-year average full forced outage rate of 10.9%, from Table 3.4, is included on line 13 of Table 3.1 as representative of the full forced outages that may occur on the PJM system. The four-year average other unavailable capacity* rate of 3.7% is less than that forecasted by PJM for summer 1981 of 4.8%. The higher figure was used in Table 3.1 as being more appropriate. The 35.4% planned reserve based on peak demand, however, is well above the PJM agreement criterion of 22 percent for planned reserves. With allowance for all possible outages of 20.2% of planned capability, MAAC would have an actual reserve of 9.9% as indicated

* Including TMI 1 and TMI 2.

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on Table 3.1 for summer 1981. The MAAC area's reserves should be adequate to meet load responsibility. However, the PJM 1981 forecasted peak is 687MW less than the actual 1980 peak and the actual 1980 peak was reduced approximately 775MW as a result of voltage reduction and public appeals. If the 1981 peak is higher than estimated or if the Salem Unit #2 is further delayed beyond the summer peak, the possibility exists for voltage reductions or more serious consequences. This could be further complicated in the MAAC area because the transmission system lacks reserve capability for large-scale additional transfers to the eastern portion without adversely affecting the reliability for emergency interchange. This has created some operational problems related to voltage and reactive limitations on internal MAAC transmission. Load flow studies and on-line reactive contingency analyses are being undertaken by PJM to find a remedy for this situation. The Hosensack-Elroy 500 Kv line was completed on March 22, 1981 and will provide some relief for PJM transmission problems. The Baltimore-Washington 500 Kv loop, which is still in litigation, is a critical transmission line for the near term period, that could provide some relief for the PJM transmission problem if it were in operation.

Fig. 3.1 indicates the non-simultaneous emergency transfer capabilities between Reliability Councils for 1981, the number of inter-regional transmission lines 345 Kv and higher, and firm power scheduled at the time of the MAAC summer peak.

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TABLE 3.1

MID ATLANTIC AREA COUNCIL (MAAC)

TABULATION OF ESTIMATED LOAD AND SUPPLY FOR THE SUMMER 1981 PEAK PERIOD

	PENNSYLVANIA NEW JERSEY MARYLAND INTERCONNECTION (PJM)	TOTAL MAAC[1] REGION
1. PLANNED CAPABILITY (MW)	46176	46176
2. PEAK DEMAND (MW)	34102	34102
3. PLANNED RESERVES (MW)(1-2)	12074	12074
4. PLANNED RESERVES (%) (3/2) X 100	35.4	35.4
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	607	607
6. TOTAL CAPABILITY (MW) (1+5)	46783	46783
7. TOTAL RESERVES (MW) (6-2)	12681	12681
8. TOTAL RESERVES (%) (7/2) X 100	37.2	37.2
9. SCHEDULED MAINTENANCE (MW) [2]	2050	2050
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	44733	44733
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	10631	10631
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	31.2	31.2
13. FULL FORCED OUTAGES (MW) [3]	5033	5033
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	39700	39700
15. AVAILABLE RESERVES (MW) (14-2)	5598	5598
16. AVAILABLE RESERVES (%) (15/2) X 100	16.4	16.4
17. OTHER UNAVAILABLE CAPABILITY (MW) [4]	2229	2229
18. AVAILABLE CAPABILITY (MW) (14-17)	37471	37471
19. ACTUAL RESERVES (MW) (18-2)	3369	3369
20. ACTUAL RESERVES (%) (19/2) X 100	9.9	9.9

[1] ALL LIAISON MEMBER SYSTEMS HAVE BEEN INCORPORATED WITH APPROPRIATE BULK POWER MEMBER SYSTEMS FOR THE PURPOSE OF THIS REPORT.

[2] AS REPORTED BY PJM.

[3] COMPUTED AT THE FOUR YEAR AVERAGE SUMMER FORCED OUTAGE RATE. FROM FPC FORM 12E-2 DATA.

[4] OTHER UNAVAILABLE CAPABILITY IS PARTIAL UNIT FORCED OUTAGES, DERATINGS AND THAT WHICH IS OUT OF SERVICE FOR LACK OF FUEL OR MANPOWER, OR HAS BEEN DEACTIVATED AND COULD REQUIRE SEVERAL WEEKS TO BE PUT ON LINE. THIS INCLUDES TMI #1 AND TMI #2, AS REPORTED BY PJM.

TABLE 3.2
ACTUAL AND PROJECTED GENERATION BY FUEL TYPE
MID ATLANTIC AREA COUNCIL

Fuel Type	Actual July 1980 Generation (MWH)	% of Total	Projected July 1981 Generation (MWH)	% of Total
Hydro	68,000	0.5	168,014	1.0
Coal	8,406,000	57.8	9,117,373	57.8
Gas	876,000	6.0	848,197	5.4
Oil	2,428,000	16.7	2,159,936	13.7
Nuclear	2,754,000	19.0	3,524,509	22.3
Pump Storage (Net)	NA	NA	(36,616)	(0.2)
Other	-	-	-	-
Total	14,532,000	100.0	15,781,413	100.0

Source: Actual Data - Electric Power Monthly-August 1980
Projected Data - ERA Form 160

TABLE 3.3
GAS AND OIL USE PROJECTION FOR JULY 1981
VS
ACTUAL GAS AND OIL USE FOR JULY 1980
MID ATLANTIC AREA COUNCIL

Fuel Type	July 1981 Projection	July 1980 Actual	Percent 7-81/7-80
Gas (MCF)	10,032	10,568	94.9
Oil (BBLS)	4,018,652	4,441,000	90.5

Source: Actual Data - Electric Power Monthly-August 1980
Projected Data - ERA Form 160

TABLE 3.4
AVERAGE GENERATING CAPACITY UNAVAILABLE AT THE TIME OF THE
SUMMER SYSTEM PEAK DEMAND 1977, 1978, 1979, 1980
MID ATLANTIC AREA COUNCIL

Month-Year	Scheduled Maintenance		Full Forced Outages		Other Unavailable Capacity	
	(MW)	% of Install Capacity	(MW)	% of Install Capacity	(MW)	% of Install Capacity
July 1977	1035	2.2	5928	12.4	2163	4.5
August 1978	1559	3.3	1907	4.0	2548	5.3
August 1979	1459	3.0	6519	13.4	725	1.5
July 1980	1729	3.6	6768	13.9	1602	3.3
4-Yr. Average		3.0		10.9		3.7

Source: FPC Form 12E-2

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TRANSFER CAPABILITY BETWEEN MAAC AND ADJACENT COUNCILS

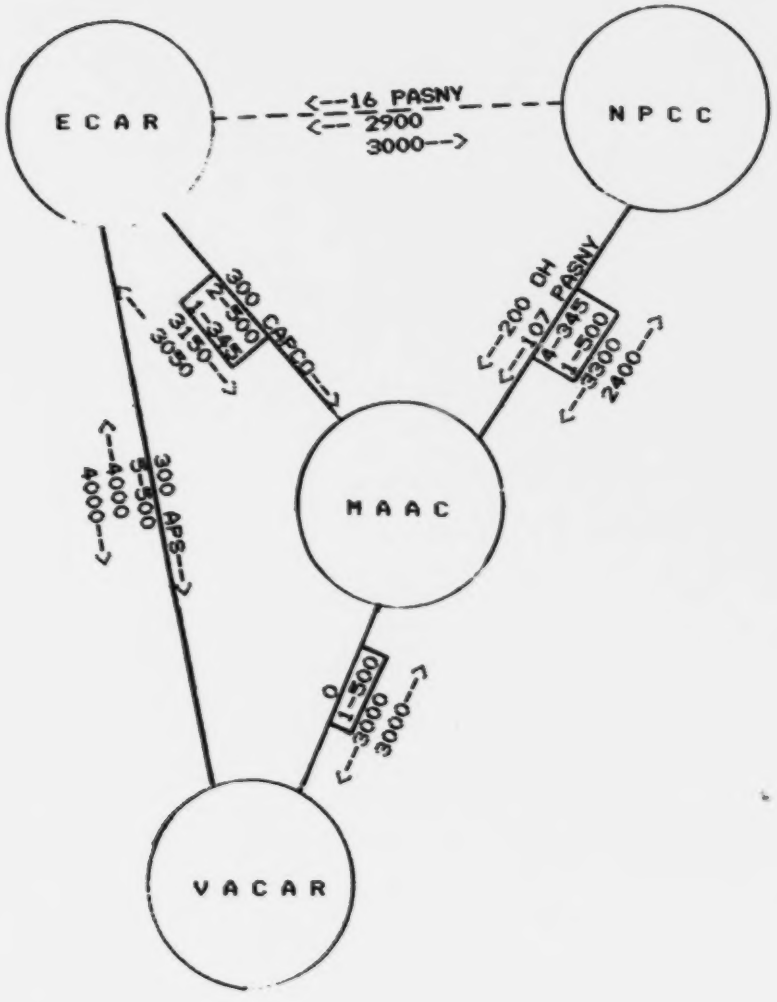

FIGURE 3.1

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4. MID-AMERICA INTERPOOL NETWORK (MAIN)

The MAIN area includes all of the State of Illinois and parts of Michigan, Wisconsin and Missouri. The area is subdivided for purposes of this report, into Electric Region 6, Commonwealth Edison Company Area (ER6-CECO); Electric Region 17, Illinois-Missouri Group (ER17-ILLMO); and Electric Region 19, Wisconsin-Upper Michigan Systems Group (ER19-WUMS).

The noncoincident summer peak load of the MAIN region is projected to be 34,993 MW; this is 3.2 percent greater than the actual summer 1980 demand (33,915 MW) and is reduced 980 MW or 2.7 percent from the forecast made in April 1980. Most of the reduction in the forecast occurs in Electric Region 6, Commonwealth Edison Company area. During the summer periods of 1977-1980, the peak demand grew at an effective compound rate of 1.8 percent.

The planned summer capability is estimated to be 41,106 MW. No major new capacity is scheduled to be completed during the summer. The planned reserve margin is forecasted to be 6,113 MW or 17.5 percent of the projected peak demand. Net power transfer of 759 MW into the region increases the margin to 6,872 MW or 19.6 percent. Allowance for scheduled maintenance of 1,029 MW reduces the reserve margin after maintenance to 5,843 MW or 16.7 percent. Full forced outages during the 1977-1980 summer periods averaged 3.8 percent of installed capability; if forced outages of this magnitude were to occur this summer, the reserve margin would be reduced to 4,288 MW or 12.3 percent. Allowance for other unavailable capability, which averaged 11.9 percent over the 1977-1980 summers, reduces the projected actual reserve margin to 0.3 percent.

In addition to MAIN's installed reserve capability, emergency transfer capability exists between MAIN and adjacent Reliability Council areas through several high voltage ties. Recent operating studies by MAIN indicate the following non-simultaneous values for emergency assistance above contracted schedules:

ECAR to MAIN - 2,900 MW	SERC to MAIN - 1,800 MW*
MARCA to MAIN - 400 MW	SPP to MAIN - 2,400 MW

* After implementation of an operating guide.

Commonwealth Edison Company
Electric Region 6

Within the MAIN region, Electric Region 6 (Commonwealth Edison Company Area) is projected to have a summer peak demand of 15,047 MW. This is 5.4 percent above the actual summer 1980 demand (14,275 MW) and is reduced 784 MW or 5.0 percent from the forecast made in April 1980. During the 1977-1980 summer periods, the area showed essentially no growth in peak demand.

The planned capability of 16,499 MW results in a planned reserve margin of 1,452 MW or 9.6 percent of the expected peak demand. Power transactions with other utilities planned during the period consists of 624 MW of firm commitment from the Michigan Systems in ECAR. This increases the total reserves to 2,076 MW or 13.8 percent. Based on the 1977-1980 historic summer rate of 2.0 percent of generating capability being on scheduled maintenance during the occurrence of the peak load, capability unavailable because of maintenance amounts to 330 MW, resulting in a reserve margin after maintenance of 1,746 MW or 11.6 percent.

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Full forced outages over the 1977-1980 summer periods averaged 7.2 percent of installed capability during the peak occurrence. If the forced outages which occur this summer approximate the average which occurred over the past four years, the reserve margin would be 558 MW or 3.7 percent. Allowance for other unavailable capability, which averaged 17.8 percent 1/ over the 1977-1980 summer periods, reduces the projected actual reserve margin to -2,379 MW or a negative 15.8 percent. There is expected to be enough other capability available within MAIN to supply emergency power, if necessary. In addition, some of the capacity scheduled for maintenance possibly could be delayed, if required.

Illinois-Missouri Group (ILLMO)
Electric Region 17

The ILLMO Region is projected to have a noncoincident summer peak demand of 12,912 MW. This is 0.3 percent less than the actual summer 1980 demand (12,946) and is reduced 127 MW or 1.0 percent from the forecast in April 1980. The load had an average annual growth of 3.4 percent for the 1977-1980 summers.

The planned installed capability of 15,693 MW results in a planned reserve margin of 2,781 MW or 21.5 percent. Net power transfers of 144 MW into the region increases the margin to 2,925 MW or 22.7 percent. Allowance for scheduled maintenance of 235 MW reduces the reserves after maintenance to 2,690 MW or 20.8 percent. Full forced outages during the summer periods of 1977-1980 averaged 1.2 percent of installed capability. Forced outages of this magnitude would reduce this summer's reserves to 2,439 MW or 18.9 percent. Allowance for other unavailable capability, which averaged 5.3 percent during the 1977-1980 summers, reduces the projected actual reserve margin to 1,607 MW or 12.4 percent. This should be adequate to cover other contingencies should they occur.

Wisconsin-Upper Michigan Systems (WUMS)
Electric Region 19

The WUMS Region is projected to have a noncoincident peak demand of 7,034 MW. This is 5.1 percent above the actual summer 1980 demand (6,694 MW) and is 69 MW or 1.0 percent less than the 7,103 MW forecasted in April 1980. The summer peak demand during 1977-1980 actually grew at a rate of 1.0 percent annually.

The planned installed capability of 8,914 MW results in a planned reserve margin of 1,880 MW or 26.7 percent. Net power transfers of 9 MW out of the region decreases the margin to 1,871 MW or 26.6 percent. Allowance for scheduled maintenance of 464 MW reduces the margin to 20.0 percent. Full forced outages during the 1977-1980 summer periods averaged 1.3 percent of installed capability. If the same magnitude of outages were to occur this summer, the actual reserves would be 1,291 MW or 18.4 percent. Allowance for other unavailable capability, which averaged 4.5 percent during the 1977-1980 summer periods, reduces the projected actual reserve margin to 890 MW or 12.7 percent. This should be adequate for coverage of contingencies.

1/ Due to partial forced outages; partial maintenance; reduced capability (derating) of some units because of the use of low-sulfur coal and environmental restrictions on cooling water temperature rise and stack gas emissions; problems with combustion turbine peaking units.

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TABLE 4.1

MID-AMERICA INTERPOOL NETWORK (MAIN)

TABULATION OF ESTIMATED LOAD AND SUPPLY FOR SUMMER 1981 PEAK PERIOD

MW OR PERCENT	COMMONWEALTH EDISON (CECO)	ILLINOIS-MISSOURI GROUP (ILLMO)	WISCONSIN-UPPER MICH. GROUP (WUMS)	TOTAL MAIN REGION
1. PLANNED CAPABILITY	16499	15693	8914	41106
2. PEAK DEMAND	15047	12912	7034	34993
3. PLANNED RESERVES (1-2)	1452	2781	1880	6113
4. PLANNED RESERVES (%) (3/2)X100	9.6	21.5	26.7	17.5
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	624	144	-9	759
6. TOTAL CAPABILITY (1+5)	17123	15837	8905	41865
7. TOTAL RESERVES (6-2)	2076	2925	1871	6872
8. TOTAL RESERVES (%) (7/2)X100	13.8	22.7	26.6	19.6
9. SCHEDULED MAINTENANCE	330	235	464	1029
10. CAPABILITY AFTER MAINTENANCE (6-9)	16793	15602	8441	40836
11. RESERVES AFTER MAINTENANCE (10-2)	1746	2690	1407	5843
12. RESERVES AFTER MAINTENANCE (%) (11/2)X100	11.6	20.8	20.0	16.7
13. FULL FORCED OUTAGES /1/	1188	251	116	1555
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	15605	15351	8325	39281
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	558	2439	1291	4288
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	3.7	18.9	18.4	12.3
17. OTHER UNAVAILABLE CAPABILITY /1/ /2/	2937	832	401	4170
18. ACTUAL CAPABILITY (14-17)	12668	14519	7924	35111
19. ACTUAL RESERVES (18-2)	-2379	1607	890	118
20. ACTUAL RESERVES (%) (19/2)X100	-15.8	12.4	12.7	0.3

/1/ SCHEDULED MAINTENANCE, OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL AVERAGES AT THE TIME OF THE SUMMER PEAKS BEGINNING WITH THE 1977 SUMMER. DATA OBTAINED FROM FPC FORM 12E-2.

/2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

5. MID-CONTINENT AREA RELIABILITY COORDINATION AGREEMENT (MARCA)
Electric Region 20

The United States portion of MARCA includes all of the states of Iowa, Minnesota, Nebraska, North Dakota and portions of Illinois, Montana, South Dakota and Wisconsin. The Mid-Continent Area Power Pool (MAPP) coordinates the planning of bulk power supply and daily operations of all major utilities in the MARCA area. The Manitoba (Canada) Hydroelectric Board (MHEB) is an Associate Member of MARCA; however, its generating resources and loads have not been included in this report, except to the extent of firm transaction with MARCA members.

Two 230-Kilovolt ties between Manitoba Hydro and the MARCA transmission network could provide emergency support to the United States systems if capacity is available in Manitoba. A new 500 kV line between Manitoba and MARCA systems was energized in May 1980, which can provide additional emergency support. Recent seasonal operating studies by MAPP indicate that the MARCA bulk power system is capable of supplying firm power transfers with enough excess transfer capability for scheduling significant amounts of emergency and economy energy. Interregional nonsimultaneous emergency tranfer capabilities with the MAIN region derived from operating studies are given as 1,200 MW import and 400 MW export. Import capability from the Southwest Power Pool (SPP) is approximately 500 MW and export capability to SPP is about 900 MW.

MARCA is projected to have a noncoincident summer peak demand of 20,039 MW. This is 3.2 percent above the actual summer 1980 demand (19,412) but is 5.8 percent below that forecasted in April 1980. The load grew at an average annual rate of 3.3 percent during the 1977-1980 summer periods. Hence, the projected peak would appear to be in line with the historic growth pattern.

The planned installed capability is 27,659 MW. This includes 410 MW of the Coyote No. 1 generating unit and 675 MW of the Ottumwa No. 1 unit planned for operation in May 1981 and 550 MW of the Laramie River No. 2 unit scheduled for June 1981. The planned reserve margin is 7,620 MW or 38.0 percent. Net power transfers of 487 MW into the region increased the margin to 8,107 MW or 40.5 percent. Based on the 1977-1980 historic summer periods rate of 1.9 percent of generating capability being on scheduled maintenance during the occurrence of the peak load, capability unavailable because of maintenance amounts to 526 MW, resulting in a reserve margin of 7,581 MW or 37.8 percent. Full forced outages during the 1977-1980 summer periods averaged 5.3 percent of installed capability. If the same magnitude of outages were to occur this summer, the reserves would be 6,115 MW or 30.5 percent. Allowance for other unavailable capability, which averaged 1.8 percent over lht 30.5 percent. Allowance for other unavailable capability, which averaged 1.8 percent over the 1977-1980 summer periods, reduces the projected actual reserves to 5,617 MW or 28.0 percent. This should be more than adequate for coverage of unforeseen contingencies. If the units scheduled for May and June were not in service before the summer peak, the reserve margin would still be 3,882 MW or 14.4 percent.

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TABLE 5.1
MID-CONTINENT AREA RELIABILITY COORDINATION AGREEMENT (MARCA)

TABULATION OF ESTIMATED LOAD AND SUPPLY FOR SUMMER 1981 PEAK PERIOD

	MW OR PERCENT	TOTAL MARCA REGION
1.	PLANNED CAPABILITY	27,659
2.	PEAK DEMAND	20,039
3.	PLANNED RESERVES (1-2)	7,620
4.	PLANNED RESERVES (%) (3/2)X100	38.0
5.	NET TRANSACTIONS (IMPORTS-EXPORTS)	487
6.	TOTAL CAPABILITY (1+5)	28,146
7.	TOTAL RESERVES (6-2)	8,107
8.	TOTAL RESERVES (%) (7/2)X100	40.5
9.	SCHEDULED MAINTENANCE /1/	526
10.	CAPABILITY AFTER MAINTENANCE (6-9)	27,620
11.	RESERVES AFTER MAINTENANCE (10-2)	7,581
12.	RESERVES AFTER MAINTENANCE (%) (11/2)X100	37.8
13.	FULL FORCED OUTAGES /1/	1,466
14.	CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	26,154
15.	RESERVES AFTER FULL FORCED OUTAGES (14-2)	6,115
16.	RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	30.5
17.	OTHER UNAVAILABLE CAPABILITY /1/ /2/	498
18.	ACTUAL CAPABILITY (14-17)	25,656
19.	ACTUAL RESERVES (18-2)	5,617
20.	ACTUAL RESERVES (%) (19/2)X100	28.0

/1/ SCHEDULED MAINTENANCE, OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL AVERAGES AT THE TIME OF THE SUMMER PEAKS BEGINNING WITH THE 1977 SUMMER. DATA OBTAINED FROM FPC FORM 12E-2.

/2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

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Northeast Power Coordinating Council (NPCC)
Electric Regions 3 and 4

The Northeast Power Coordinating Council (NPCC) includes all of New England, New York, Ontario and New Brunswick. Twenty-one utility member systems divided into four planning and operating entities or subregions -- two in the United States and two in Canada -- comprise the Council. This report addresses only the two Electric Regions in the United States portion of the Council, the New England Power Pool (NEPOOL) and the New York Power Pool (NYPP).

The non-coincident NPCC peak load forecast for the summer season 1981 as shown on line 2 of Table 6.1 is 35,843 megawatts. This is a 3.0 percent decrease below the actual peak of the previous summer, and a 2.0 percent increase over the summer peak of 1979. The summer peak of 1980 was higher than normal primarily due to unusually hot weather. NEPOOL is a winter peaking system, NYPP is a summer peaking group, and therefore some interpool diversity exists. Each pool takes advantage of inter-system diversity in establishing its reserve criteria and scheduling maintenance.

Planned capability to meet the 1981 summer peak load forecast is 51,007 megawatts. In addition NPCC has scheduled 882 MW of firm receipts from Hydro Quebec, New Brunswick and Southern Canada for the forecast period. There are no major generating additions scheduled for installation during the summer peak period.

Both U.S. areas of NPCC are heavily dependent on oil for the production of electric energy. This dependence on oil adversely impacts the cost of electric power supply. Oil-fired generation represented 43% of the total energy produced in July 1980; nuclear generation 23%; hydro 14%; coal 10% and gas and other sources 10%. Table 6.2 indicates projected generation by fuel type for July 1981 based on ERA Form 160, and actual July 1980 generation taken from the Energy Information Administration (EIA) Electric Power Monthly Report dated August 1980. Table 6.3 compares actual use of gas and oil in July 1980 with the projected use of those fuels for July 1981.

Table 6.4 shows the four year average generating capacity unavailable at the time of the summer system peak for the period 1977 through 1980. The diversity between the seasonal peaks of each regional area allows for coordination of scheduling of maintenance during the appropriate season to avoid having excessive amounts of capacity unavailable.

The NPCC four-year scheduled maintenance average was 7.7%. For summer 1981 the corresponding amount is 3,929 MW as shown on line 9 of Table 6.1. The capacity on forced outage for NPCC as shown in Table 6.1 line 13, is based on the four-year average of forced outages in megawatts; it is a representative forced outage rate that may occur in NPCC. The calculated four-year average unavailable capacity is shown on line 17 of Table 6.1.

As indicated on Table 6.1 for Summer 1981, NPCC will have adequate reserves to meet its load responsibility. The 13.1 percent reserves after all projected outages is well above the NPCC required operating reserves. Total planned reserves are 42.3% before consideration of possible outages and the net of imports and exports.

No major transmission lines are scheduled for completion prior to the 1981 peak. The transmission system appears adequate to cover load commitments for the period with no stability problem areas.

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New England Power Pool (NEPOOL)
Electric Region 3

NEPOOL is the coordinating pool for the New England states; it includes over forty privately and publicly owned utilities operating in the six New England States.

NEPOOL is a winter peaking Region, though some systems in Connecticut have a summer peak. The peak load forecast for the summer of 1981 is 14,780 megawatts. This is a 1.4% decrease below the actual peak of the previous summer and 3.4% lower than the winter peak of 1980-81. The annual summer growth rate for the past 3 years has been 3.8%, while the annual winter peak growth for the same period was 3.6%. These rates reflect the general reduction in the region's economic activity.

Capability planned to meet the 1981 summer peak load forecast is 20,644 megawatts. No new generating capacity is expected to be available for the summer peak season, but it is anticipated that two of the three units at the Brayton Point Plant of the New England Electric System that are being converted from oil to coal fuel will be completed prior to the summer peak. However, the major portion of the NEPOOL generation is oil-fired and represents 54% of the energy generated in July 1980, while nuclear-fueled generation represented 37%. Table 6A.2 indicates projected generation by fuel type for July 1981 based on ERA-Form 160, and actual data for July 1980. Table 6A.3 provides fuel use projections for oil and gas for July 1981 and actual use for July 1980. Table 6A.4 shows the average generating capacity unavailable at the time of the summer peak for the period 1977-1980 based on the data submitted on the FPC Form 12E-2.

The NEPOOL calculated scheduled maintenance based on a four year summer average and summarized in Table 6A.4 is 8.0%. The four year summer forced outage rate is 8.6% and the four year summer average of other unavailable capability is 7.3%. These are shown in Table 6.1, lines 9, 13 and 17, as the outages that might be experienced during the summer season.

As shown in Table 6.1 for summer 1981, the NEPOOL Region will have adequate reserves to meet its load responsibility. Planned reserves are 39.7%, and actual reserves, after scheduled maintenance, forced outages and other unavailable capability, are 8.7%. During the summer season, no transmission problems should be experienced unless there is an unexpected generating unit forced outage for a protracted period, coupled with a transmission line outage.

New York Power Pool
Electric Region 4

The New York Power Pool (NYPP) coordinates the planning and operation of the eight major electric utility systems in New York State, and is the only pool in the contiguous U.S. where the Electric Region and geographic region are defined by the state boundary.

The State of New York is summer peaking. Although the northern portion of the State has a winter peak, the larger loads of the downstate utilities cause the overall state peak to occur in the summer. The peak forecast for the summer 1981 is 21,063 megawatts. This is a 4.2% decrease below the previous summer and 9% higher than the winter peak. The summer peak growth in NYPP has been depressed over the last three years, reflecting load conservation, mild summers and depressed economic

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conditions. Planned capability to meet the coming summer peak load is 30,363 megawatts. No major additions of capacity are expected prior to the summer season. New York, while not being quite as dependent on fuel oil as New England, generated 36% of its electric energy from oil in July 1980. Hydro-electric capacity, the bulk of which is from the St. Lawrence and Niagara projects of the Power Authority of the State of New York, represented 22% of July 1980 generation. Nuclear, coal, and gas fired generation were 15%; 12%; and 15% respectively.

Table 6B.2 provides projected generation by fuel type for July 1981, based on Form ERA-160 and actual data for July 1980. Table 6B.3 compares actual 1980 (July) use of oil and gas (Electric Power Monthly for August 1980) with projected 1981 (July) data from the ERA Form 160. Gas-fired generation is expected to decrease substantially while nuclear generation will take up the slack for the month of July 1981. The use of fuel oil for the past four years has decreased in the NYPP; coal use is predicted to increase. Oil use is projected to remain approximately constant.

Table 6B.4 shows the average generating capacity unavailable at the time of the summer system peak for the past four summers and the four year average. Scheduled maintenance over the past four summer seasons averaged 7.5%, forced outages averaged 8.6% and other unavailable capacity 5.0%. Scheduled maintenance requirements over the past four years has shown a marked increase from 5.5% of installed capacity in 1977 to 10% in 1980. The reason for the increase is the annual refueling and maintenance of nuclear units during the summer on systems in the state that peak during the winter. Additionally, in 1980 there was unusual maintenance performed on several large generating units of Niagara Mohawk Power Company (Oswego #5, and the Huntley and Dunkirk Units).

As indicated on Table 6.1 for summer 1981, the NYPP Region should have actual reserves of about 16.2%, which is adequate to meet its load responsibility. The NYPP reserve criterion calls for a planned reserve of 22% before effect is given to the net of imports and exports and to possible outages of capacity; Table 6.1 shows the planned reserve is 44.2%.

It is expected that the repairs necessitated by the accident at Indian Point No. 2 Nuclear Unit, salt water intrusion into the reactor vessel, will be completed in time to make the unit available for service during the summer peak period.

Lack of adequate North-to-South transmission capacity prevents economic dispatch of some New York Power Pool resources during off-peak hours in the summer peak period. Northwestern New York has lower-cost capacity available during those hours, from NYPP units and from Ontario Hydro, that could be utilized elsewhere in the State. However, transmission constraints prevent transfer of this power to other areas. Additional and alternate transmission facilities, planned and under construction, are expected to alleviate this situation.

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TABLE 6.1

NORTHEAST POWER COORDINATING COUNCIL (NPCC)

TABULATION OF ESTIMATED LOAD AND SUPPLY FOR THE SUMMER 1981 PEAK PERIOD

	NEW ENGLAND POWER POOL (NEPOOL)	NEW YORK POWER POOL (NYPP)	TOTAL NPCC[1] REGION
1. PLANNED CAPABILITY (MW)	20644	30363	51007
2. PEAK DEMAND (MW) [2]	14780	21063	35843
3. PLANNED RESERVES (MW)(1-2)	5864	9300	15164
4. PLANNED RESERVES (%) (3/2) X 100	39.7	44.2	42.3
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW) [2]	362	520	882
6. TOTAL CAPABILITY (MW) (1+5)	21006	30883	51889
7. TOTAL RESERVES (MW) (6-2)	6226	9820	16046
8. TOTAL RESERVES (%) (7/2) X 100	42.1	46.6	44.8
9. SCHEDULED MAINTENANCE (MW) [3]	1652	2277	3929
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	19354	28606	47960
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	4574	7543	12117
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	30.9	35.8	33.8
13. FULL FORCED OUTAGES (MW) [4]	1775	2611	4386
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	17579	25995	43574
15. AVAILABLE RESERVES (MW) (14-2)	2799	4932	7731
16. AVAILABLE RESERVES (%) (15/2) X 100	18.9	23.4	21.6
17. OTHER UNAVAILABLE CAPABILITY (MW) [5]	1507	1518	3025
18. AVAILABLE CAPABILITY (MW) (14-17)	16072	24477	40549
19. ACTUAL RESERVES (MW) (18-2)	1292	3414	4706
20. ACTUAL RESERVES (%) (19/2) X 100	8.7	16.2	13.1

[1] ALL LIAISON MEMBER SYSTEMS HAVE BEEN INCORPORATED WITH APPROPRIATE BULK POWER MEMBER SYSTEMS. FOR THE PURPOSE OF THIS REPORT.

[2] THE NYPP & NPCC PEAK AS REPORTED IN THE FORM 411 HAS BEEN REDUCED BY 107 MW TO REFLECT A DELIVERY BY PASNY TO MAAC FOR ALLEGHENY ELECTRIC COOP. THIS DELIVERY IS NOT REPORTED IN THE NPCC FORM 411.

[3] COMPUTED AT THE FOUR YEAR AVERAGE SUMMER SCHEDULED MAINTENANCE RATE (FPC FORM 12E-2)

[4] COMPUTED AT THE FOUR YEAR AVERAGE SUMMER FORCED OUTAGE RATE. (FPC FORM 12E-2)

[5] OTHER UNAVAILABLE CAPABILITY IS PARTIAL UNIT FORCED OUTAGES, DERATINGS AND THAT WHICH IS OUT OF SERVICE FOR LACK OF FUEL OR MANPOWER, OR HAS BEEN DEACTIVATED AND COULD REQUIRE SEVERAL WEEKS TO BE PUT ON LINE. COMPUTED AT THE FOUR YEAR AVERAGE UNAVAILABLE CAPABILITY RATE.

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TABLE 6.2

ACTUAL AND PROJECTED GENERATION BY FUEL TYPE
NORTHEAST POWER COORDINATION COUNCIL

FUEL TYPE	ACTUAL JULY 1980 GENERATION (MWH)	% OF TOTAL	PROJECTED JULY 1981 GENERATION (MWH)	% OF TOTAL
HYDRO	2,323,000	14.3	2,295,076	14.5
COAL	1,572,000	9.6	1,685,200	10.7
GAS	1,578,000	9.7	1,193,830	7.6
OIL	6,961,000	42.9	6,807,130	43.2
NUCLEAR	3,807,000	23.4	3,910,902	24.8
PUMP STORAGE (NET)	NA	NA	(140,000)	(0.9)
OTHER	2,000	0.1	16,000	0.1
TOTAL	16,243,000	100.0	15,768,138	100.0

SOURCE: ACTUAL DATA - ELECTRIC POWER MONTHLY - AUGUST 1980
PROJECTED DATA - ERA FORM 160

TABLE 6.3

GAS AND OIL USE PROJECTION FOR JULY 1981
VS
ACTUAL GAS AND OIL USE FOR JULY 1980
NORTHEAST POWER COORDINATION COUNCIL

FUEL TYPE	JULY 1981 PROJECTION	JULY 1980 ACTUAL	PERCENTAGE 7-81/7-80
GAS (MCF)	13,272 *	18,302	72.5
OIL (BBLS)	11,575,779	11,558,000	100.2

* INCLUDES 1,243 MCF PROPANE

SOURCE: ACTUAL DATA - ELECTRIC POWER MONTHLY - AUGUST 1980
PROJECTED DATA - ERA FORM 160

TABLE 6.4

AVERAGE GENERATING CAPACITY UNAVAILABLE AT THE TIME OF THE
SUMMER SYSTEM PEAK DEMAND 1977,1978,1979,1980
NORTHEAST POWER COORDINATION COUNCIL

MONTH-YEAR	SCHEDULED MAINTENANCE		FULL FORCED OUTAGES		OTHER UNAVAILABLE CAPACITY	
	(MW)	% OF INSTALL CAPACITY	(MW)	% OF INSTALL CAPACITY	(MW)	% OF INSTALL CAPACITY
JULY 1977	4154	7.9	3916	7.5	3408	6.5
AUG. 1978	4117	7.8	4376	8.3	3123	5.9
AUG. 1979	3460	6.3	6351	11.6	3444	6.3
JULY 1980	4796	8.7	3838	7.0	2921	5.3
4-YR. AVERAGE		7.7		8.6		6.0

SOURCE: FPC FORM 12E-2

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TABLE 6A.2
ACTUAL AND PROJECTED GENERATION BY FUEL TYPE
NEW ENGLAND POWER POOL

FUEL TYPE	ACTUAL JULY 1980 GENERATION (MWH)	% OF TOTAL	PROJECTED JULY 1981 GENERATION (MWH)	% OF TOTAL
HYDRO	161,000	2.5	217,776	3.8
COAL	378,000	5.8	525,000	9.0
GAS	87,000	1.3	-	-
OIL	3,539,000	53.9	3,371,138	58.1
NUCLEAR	2,400,000	36.5	1,739,202	29.9
PUMP STORAGE (NET)	NA	NA	(46,000)	(0.8)
OTHER	3,000	0.0	-	-
TOTAL	6,568,000	100.0	5,807,116	100.0

SOURCE: ACTUAL DATA - ELECTRIC POWER MONTHLY - AUGUST 1980
PROJECTED DATA - ERA FORM 160

TABLE 6A.3

GAS AND OIL USE PROJECTION FOR JULY 1981
VS
ACTUAL GAS AND OIL USE FOR JULY 1980
NEW ENGLAND POWER POOL

FUEL TYPE	JULY 1981 PROJECTION	JULY 1981 ACTUAL	PERCENTAGE 7-81/7-80
GAS (MCF)	1,243 *	1,078	115.3
OIL (BBLS)	5,721,546	5,873,000	97.4

* PROPANE

SOURCE: ACTUAL DATA - ELECTRIC POWER MONTHLY - AUGUST 1980
PROJECTED DATA - ERA FORM 160

TABLE 6A.4

AVERAGE GENERATING CAPACITY UNAVAILABLE AT THE TIME OF THE
SUMMER SYSTEM PEAK DEMAND 1977,1978,1979,1980
NEW ENGLAND POWER POOL

MONTH-YEAR	SCHEDULED MAINTENANCE		FULL FORCED OUTAGES		OTHER UNAVAILABLE CAPACITY	
	(MW)	% OF INSTALL CAPACITY	(MW)	% OF INSTALL CAPACITY	(MW)	% OF INSTALL CAPACITY
JULY 1977	2438	11.7	928	4.4	1677	8.0
AUG. 1978	2026	9.9	1999	9.7	1750	8.5
AUG. 1979	827	3.9	2477	11.7	1537	7.3
JULY 1980	1402	6.7	1748	8.3	1323	6.3
4-YR. AVERAGE:		8.0		8.6		7.3

SOURCE: FPC FORM 12E-2

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TABLE 6B.2

ACTUAL AND PROJECTED GENERATION BY FUEL TYPE
NEW YORK POWER POOL

FUEL TYPE	ACTUAL JULY 1980 GENERATION (MWH)	% OF TOTAL	PROJECTED JULY 1981 GENERATION (MWH)	% OF TOTAL
HYDRO	2,159,000	22.3	2,077,300	20.8
COAL	1,193,000	12.3	1,160,200	11.6
GAS	1,491,000	15.4	1,193,830	12.0
OIL	3,422,000	35.4	3,435,992	34.5
NUCLEAR	1,407,000	14.6	2,171,700	21.8
PUMP STORAGE (NET)	NA	NA	(94,000)	(0.9)
OTHER	-	-	16,000	0.2
TOTAL	9,672,000	100.0	9,961,022	100.0

SOURCE: ACTUAL DATA - ELECTRIC POWER MONTHLY - AUGUST
PROJECTED DATA - ERA FORM 160

TABLE 6B.3

GAS AND OIL USE PROJECTION FOR JULY 1981
VS
ACTUAL GAS AND OIL USE FOR JULY 1980
NEW YORK POWER POOL

FUEL TYPE	JULY 1981 PROJECTION	JULY 1980 ACTUAL	PERCENTAGE 7-81/7-80
GAS (MCF)	12,029	17,224	69.8
OIL (BBLS)	5,854,233	5,686,000	102.96

SOURCE: ACTUAL DATA - ELECTRIC POWER MONTHLY - AUGUST 1980
PROJECTED DATA - ERA FORM 160

TABLE 6B.4

AVERAGE GENERATING CAPACITY UNAVAILABLE AT THE TIME OF THE
SUMMER SYSTEM PEAK DEMAND 1977,1978,1979,1980
NEW YORK POWER POOL

MONTH-YEAR	SCHEDULED MAINTENANCE		FULL FORCED OUTAGES		OTHER UNAVAILABLE CAPACITY	
	(MW)	% OF INSTALL CAPACITY	(MW)	% OF INSTALL CAPACITY	(MW)	% OF INSTALL CAPACITY
JULY 1977	1716	5.5	2987	9.5	1731	5.5
AUG. 1978	2091	6.5	2377	7.4	1373	4.3
AUG. 1979	2633	7.8	3874	11.5	1907	5.6
JULY 1980	3394	10.0	2090	6.2	1598	4.7
4-YR. AVERAGE:		7.5		8.6		5.0

SOURCE: FPC FORM 12E-2

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7.0 SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL (SERC)

The Southeastern Electric Reliability Council (SERC) is comprised of four Electric Regions. Electric Region 7 covers Peninsular Florida and is represented by the Florida Electric Coordinating Group (FCG). Electric Region 9 is referred to as the Southern Company Group and its service area covers the Florida Panhandle, the southeastern quadrant of Mississippi, the southern three-fourths of Alabama, and all except a small portion of Georgia. Electric Region 11 is represented by the Tennessee Valley Authority (TVA) and serves all of Tennessee, the northeastern quadrant of Mississippi, three Cooperatives in north Georgia and southwestern portion of North Carolina, a small portion of Southwest Kentucky, and the northern quarter of Alabama. The fourth SERC group is Electric Region 12; it is referred to as the Virginia-Carolinas Group (VACAR) and serves South Carolina, all except a small Southwest portion of North Carolina, the Virginia Electric and Power Company's service area in Virginia and three counties in West Virginia.

A brief review of the actual conditions in the SERC area during last summer's record heat wave is appropriate prior to an analysis of the "Estimated Summer 1981 Electric Demand and Supply" situation. The recorded 1980 summer peaks for July and August exceeded the greatest previously recorded summer peak by 7.9 and 6.1 percent respectively. During the three month summer season of June, July and August, the net energy requirements increased by 7.1 percent. Table 7.1 shows the actual demand and supply situation for the summer 1980 peak month for each of the four Electric Regions in SERC. Table 7.2 shows the corresponding data as projected for summer 1981, with Planned Capability, Peak Demand and Net Transactions taken from the SERC ERA-411 report dated April 1, 1981.

Table 7.1
Southeastern Electric Reliability Council (SERC)
Tabulation of Actual Load and Supply
for Summer 1980 Peak Period 1/

Mw or Percent	Florida	Southern	TVA	VACAR	SERC
(1) Planned Capability	22,554	25,083	27,063	33,842	108,542
(2) Peak Demand	18,171 2/	22,690 2/	20,250 2/	29,029 3/	90,140
(3) Planned Reserve	4,383	2,393	6,813	4,813	18,402
(4) Planned Reserve (%)	24.1	10.5	33.6	16.6	20.4
(5) Net Transactions	606	3,298	485	4,189	8,578
(6) Total Capability	23,160	28,381	27,548	38,031	117,120
(7) Total Reserve	4,989	5,691	7,298	9,002	26,980
(8) Total Reserve (%)	27.5	25.1	36.0	31.0	29.9
(9) Scheduled Maint.	1,347	157	255	4,025	5,784
(10)Capability after Main	21,813	28,224	27,293	34,006	111,336
(11)Reserve after Maint.	3,642	5,534	7,043	4,977	21,216
(12)Reserve aft Maint.(%)	20.0	24.4	34.8	17.1	23.5
(13)Forced Outage	997	3314	4,738	537	9,586
(14)Avail. Cap. aft. F.O.	20,816	24,910	22,555	33,469	101,750
(15)Available Reserve	2,645	2,220	2,305	4,440	11,610
(16)Available Reserve (%)	14.6	9.8	11.4	15.3	12.9
(17)Other Unavailable	853	304	1,282	3,253	5,692
(18)Available Capability	19,963	24,606	21,273	30,216	96,058
(19)Actual Reserve	1,792	1,916	1,023	1,187	5,918
(20)Actual Reserve (%)	9.9	8.4	5.1	4.1	6.6

1/ From FPC Form 12E-2
2/ July 1980
3/ August 1980

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Table 7.2
Southeastern Electric Reliability Council
Tabulation of Estimated Load and Supply for Summer 1981 Peak Period

Mw or Percent	Florida	Southern	TVA	VACAR	SERC
(1) Planned Capability	24,529	27,975	28,232	36,333	117,069
(2) Peak Demand	18,577	21,101 2/	19,669	29,302 3/	88,649
(3) Planned Reserve	5,952	6,874	8,563	7,032	28,420
(4) Planned Reserve (%)	32.0	32.6	43.5	24.0	32.1
(5) Net Transactions	0 1/	140	(1100)	900	(60)
(6) Total Capability	24,529	28,115	27,132	37,233	117,009
(7) Total Reserve	5,952	7,014	7,463	7,931	28,360
(8) Total Reserve (%)	32.0	33.2	37.9	27.1	32.0
(9) Scheduled Maint.	1,840	503	395	2,144	4,882
(10)Capability after Main	22,689	27,612	26,737	35,089	112,127
(11)Reserve after Maint.	4,112	6,511	7,068	5,787	23,478
(12)Reserve aft Maint.(%)	22.1	30.9	35.9	19.7	26.5
(13)Forced Outage	908 4/	1,734	2,908	2,107	7,657 4/
(14)Avail. Cap. aft. F.O.	21,781	25,878	23,829	32,982	104,470
(15)Available Reserve	3,204	4,777	4,160	3,680	15,821
(16)Available Reserve (%)	17.2	22.6	21.2	12.6	17.8
(17)Other Unavailable	908	1,007	1,327	2,834	6,076
(18)Avail. Cap.	20,873	24,871	22,502	30,148	98,394
(19)Actual Reserve	2,296	3,770	2,833	846	9,745
(20)Actual Reserve (%)	12.4	17.9	14.4	2.9	11.0

1/ 400 Mw Non-firm available from Southern Company
2/ Includes 211 Mw of interruptible load.
3/ Includes 165 Mw of interruptible load.
4/ Does not include Turkey Point 3, 646 MW.

Table 7.3
Southeastern Electric Reliability Council Regions
Capacity Unavailable at Time of Summer Peak
As Percentage of Installed Capacity 1/

	Florida	Southern	TVA	VACAR
Scheduled Maintenance	7.5	1.8	1.4	5.9
Full Forced Outage	3.7	6.2	10.3	5.8
Other Unavailable	3.7	3.6	4.7	7.8

1/ Based on data reported in FPC Form 12E-2 for the years 1977 through 1980.

Table 7.3 provides the percentages that were applied to the Planned Capability of Line 1 in Table 7.2 to obtain the unavailable Capability shown on Lines 9, 13 and 17.

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The SERC forecast peak demands for the Summer 1981 season shown on Table 7.2, project an increase of 6.8 percent over the actual 1979 summer peak, the last summer having "normal" summer temperatures. This is an average annual growth of about 3.3 percent for the two year period and is consistent with the historic trend of recent years. The usual amount of load diversity was not experienced in summer 1980 because of a widespread, prolonged heat storm coupled with a significant amount of weather-sensitive load. The 1981 summer peakload forecast, however, reflects a normal load growth over the 1979-81 period with a normal diversity factor. This will be discussed more fully for each Electric Region.

Table 7.4
Southeastern Electric Reliability Council
Three year Load Growth Profile

Region	1979	1980	1981 1/
Florida	16,605	18,171	18,577
Southern	20,432	22,690	21,101
TVA	18,795	20,250	20,016
VACAR	27,492	29,029	29,302
SERC	83,324	90,140	88,966

1/ Forecast from ERA 411.

Fuel Use

Fuel use is a concern in each of the four regions in SERC with each region having its own potentially critical problem. This will be discussed in more detail in the individual section for each region. Table 7.5 shows the projected generation by fuels for the 1981 Summer peak for the SERC Region.

Table 7.5
Southeastern Electric Reliability Council
Projected Generation by Fuels for Summer 1981 Peak Month

Type Fuel	Generation (Mwh)	Percent of Total
Hydro	2,562,028	5.6
Coal	26,112,868	57.4
Gas	1,417,179	3.1
Oil	6,031,232	13.2
Nuclear	9,399,692	20.7
Other	14,600	Neg.
Total	45,537,599	100.0

Table 7.6 compares fuel consumption for the Summer 1980 and the projected consumption for the Summer 1981 for the more critical gas and oil fuels. Part of the decreased usage can be attributed to a projected return to normal summer temperatures with a reduction in the use of gas turbin peaking units.

Table 7.6
Southeastern Electric Reliability Council
Peak Month Fuel Use Projected for Summer 1981
Versus Actual for Summer 1980

Fuel Type	Summer 1981 Projection	Summer 1980 Actual	Percent of Change Summer '81 vs. Summer '80
Gas (Mcf)	16,426,000	19,719,379	(16.7)
Oil (Bbl)	10,625,512	10,834,562	(1.9)

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Transmission

Figure 7.1 shows the SERC Subregion EHV interconnecting lines, maximum transfer capacity 1/ and schedule power transfers for the summer 1981 peak load season.

Table 7.7 summarizes scheduled power transfers and transmission import capacities for each Subregion of SERC for the 1981 summer peak load situation.

Table 7.7
Southeastern Electric Reliability Council
Summary of Transmission Transfers and Import Capacity
Summer 1981

SERC Subregion	Import Capacity in Mw	Scheduled Imports in Mw	Unused Import in Mw
Florida	800	400 2/	400
Southern	5,000	140	4,460
TVA	6,700	0	5,600
VACAR	5,150	900	4,250
SERC 3/	8,650	1,860	6,790

1/ Maximum transfer capacity is estimated based on typical circuit voltage load-carrying volumes. Lines which loop through another organization's service area and change ownership but do not have an injection mode where additional power can enter or leave are not considered interconnecting lines in this analysis. In the case of three terminal interconnections, the capability was divided between interconnecting parties.

2/ Non-firm transfer.

3/ Non-Simultaneous Total. This differs from the sum of the regional amounts because of the different timing of peak load conditions among the regions and the nature of power flows among areas with multiple interconnections.

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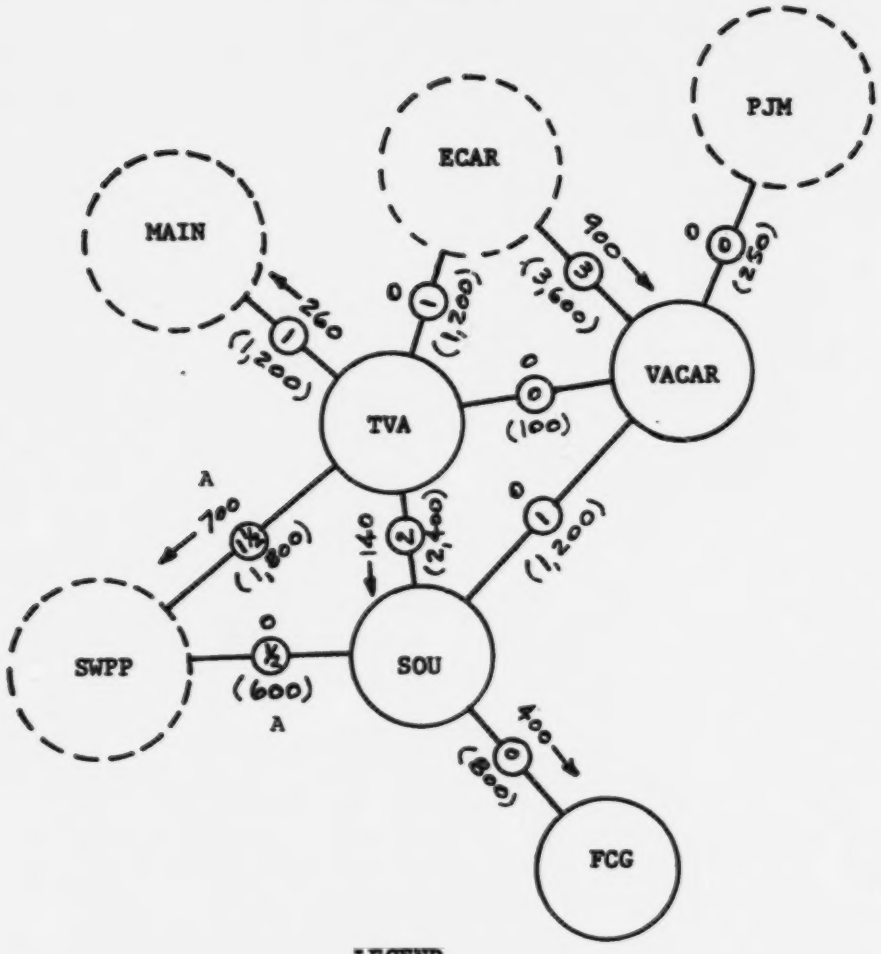
Figure 7.1

SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL

SERC Subregion Scheduled Power Transfers and Transfer Capacity

Summer 1981



LEGEND

(2) Number of Interconnecting Lines at 500 kv or Higher Voltage.

300 → / (1200) Scheduled Firm Power Transfer in Mw. / Maximum Transfer Capability in Mw. 1/

1/ Based on typical circuit capability of 1,200 Mw per circuit for 500 kv.

A - SWPP, TVA and Southern share a single line and a 3-terminal line. The diagram is not a physical representation but attempts only to indicate the power flow condition.

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Florida Coordinating Group (FCG) Region

The FCG region has the heaviest dependency on oil in the SERC area, accounting for 88 percent of the total oil consumption in SERC. Because of this, nuclear units play an important role in the upcoming summer season as well as the near future as the region explores new methods of reducing oil consumption. Table 7A.1 shows the projected generation by fuels for July 1981 and Table 7A.2 compares fuel use for July 1980 with projected use for July 1981.

Table 7A.1
Florida Coordinating Group Region
Projected Generation by Fuels for July 1981

Type Fuel	Generation (Mwh)	Percent of Total
Hydro	0	0
Coal	1,395,100	14.9
Gas	1,186,300	12.7
Oil	5,305,142	56.8
Nuclear	1,444,020	15.4
Other	14,600	0.2
Total	9,345,432	100.0

Table 7A.2
Florida Coordinating Group Region
Fuel Use Projected for July 1981
Versus Actual for July 1980

Fuel Type	July 1981 Projection	July 1980 Actual	Percent of Change July 1981 vs. July 1980
Gas (Mcf)	13,782,000	14,550,191	(5.3)
Oil (Bbl)	9,088,466	8,116,699	12.0

While the three other Electric Regions making up the SERC area experienced average 1980 summer temperatures ranging from 3.1 to 5.2 degrees above normal, the temperatures for the FCG area were well within the normal expectancy for the summer months. However, owing to the duration of the "heat wave" and its cumulative effects, the 1980 summer peak exceeded the previous year by 9.1 percent and the energy requirements increased by 5.6 percent. A comparison of the 1980 summer peak load shown on Table 7.1 with the 1981 peak load forecast shown on Table 7.2, projects a growth of 2.2 percent for this year. The FCG is also projecting a 3.1 percent increase in energy requirements. These projections for load and energy growth appear consistent with current normal growth rates for the FCG area.

As currently scheduled, the only new capability anticipated to be available for the summer load is the Gainesville Regional Utilities Deerhaven No. 2, 235 Mw coal-fired unit. This would increase the reserve shown on Table 7.2 to 2,531 Mw, or 13.6 percent.

The recent long-term outage of Turkey Point No. 3 reduces the prospect of reliable service in Florida.

Southern Company Group (SOU) Region

The Southern Company Region has the greatest energy production by coal as a percent of total production among the SERC Electric Regions. The complete summation of generation by fuel types is shown on Table 7B.1.

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Table 7B.1
Southern Company Group Region
Projected Generation By Fuels For August 1981

Type Fuel	Generation (Mwh)	Percent of Total
Hydro	339,900	3.2
Coal	8,096,418	75.6
Gas	209,679	2.0
Oil	98,620	0.9
Nuclear	1,962,080	18.3
Other	0	0
Total	10,706,697	100.0

The SOU is a summer peaking area where last year's record summer temperature resulted in a peak demand that was 24 percent higher than the winter peak. Table 7B.2 shows summer energy and weather data for 1979 (a normal weather period) and 1980. The 12.3% increase in energy for July and August, considered in relation to the 25.0% increase in cooling degree-days, indicates significant weather-sensitivity. Peak demand in the 1980 summer was about 10.8 percent greater than it was in 1979.

Table 7B.2
Southern Company Group Region
Comparison of 1980 Versus 1979 Summer Degree Days
Temperature and Energy

	Avg. Deg. Days		% Change	Avg. Temp. 1/		Energy (Gwh)		
	1980	1979	1980 vs. 1979	1980	1979	1980	1979	% Change
July	556	436	27.5	83.0	79.0	11,516	9980	15.4
August	520	425	22.4	81.8	78.7	11,434	10,458	9.3
Total	1,076	861	25.0	82.4	78.9	22,950	20,438	12.3

1/ U.S. Weather Service defines each 1.5 degrees variation from normal as a deviation. 1979 was considered a normal year.

Except for the possible curtailment of coal deliveries, the SOU appears to be in excellent shape for the 1981 Summer season. The 1981 peak load forecast actually reflects a 5.9 percent decrease over 1980. Energy requirements for this year show the same percent decrease.

The following units are currently scheduled to come on line this summer:

Utility	Unit	Mw	Fuel	In Service Date
Alabama Power Co.	Farley-2	807	Nuclear	July 1981
Mississippi Power Co.	Daniel-2	252 1/	Coal	June 1981
Gulf Power Co.	Daniel-2	252 1/	Coal	June 1981

1/ Jointly owned.

The above units are not included in the planned capability shown on Table 7.2. If these units should be available for the summer peak, the actual reserves shown on line 20 of Table 7.2 would be increased to about 21.6%.

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Tennessee Valley Authority (TVA) Region

TVA is the largest system in the SERC area, serving municipalities and cooperatives with service areas in seven states. In keeping with its original concept, TVA has many multi-purpose hydroelectric projects and produces 15.7 percent of its total energy requirements by this means. Table 7C.1 shows the complete summary of generation by fuels.

Table 7C.1
Tennessee Valley Authority Region
Projected Generation by Fuels for July 1981

Type Fuel	Generation (Mwh)	Percent of Total
Hydro	1,562,400	15.7
Coal	7,648,300	68.9
Gas	0	0
Oil	0	0
Nuclear	1,711,200	15.4
Other	0	0
Total	11,100,900	100.0

The TVA area had the greatest increase in the average temperature for the summer of 1980 of any of the four Electric Regions in SERC. The average temperature difference of 5.2 degrees as derived from Table 7C.2 amounts to approximately 3.5 deviations as defined by the U.S. Weather Service. Although the degree days increased by 49.2 percent, the net energy for the 1980 summer period only increased by 7.3 percent over the 1980 summer and the demand increased 7.7 percent. The small increase in energy requirements apparently reflects the effects of TVA conservation programs. The load growth, which averaged about 280 Mw per degree temperature rise above normal, appears consistent with TVA load forecasting projections.

Table 7C.2
Tennessee Valley Authority Region
Comparison of 1980 Versus 1979 Summer Degree Days
Temperature and Energy

	Avg. Deg. Days		% Change	Avg. Temp.		Energy (Gwh)		
	1980	1979	1980 vs. 1979	1980	1979	1980	1979	% Change
July	499	329	51.7	81.1	75.6	11,208	10,202	9.9
August	472	322	46.6	80.2	75.4	11,011	10,508	4.8
Total	971	651	49.2	80.7	75.5	22,219	20,710	7.3

From May 1980 through the winter of 1980-81, the TVA area has experienced its worst drought in 91 years of record keeping. While conditions have improved this spring, hydroelectric power supply could still be considered somewhat uncertain at this time.

After adjustment for the unusual weather conditions in the summer of 1980, the peak demand shown on Table 7.2 projects a reduction of about 2.9 percent for the 1981 summer peak. TVA also projects a reduction of about 3 percent for energy requirements.

The only new capability anticipated for the summer load will be the Sequoyah No. 1, 1148 Mw nuclear unit. It should be noted, however, that only about 600 Mw will be available. The Sequoyah capability is included in Table 7.2. After being unavailable for several months on full forced outage, the Cumberland No. 2, coal-fired, 1275 Mw unit returned to service the first week in April 1981. This leaves TVA in a good load/supply situation for the 1981 summer season, even in view of possible difficulties with hydro capacity supply.

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Virginia-Carolinas Group (VACAR) Region

On the basis of energy requirements and peak demand, VACAR is the largest of the four electric regions making up the Southeastern Electric Reliability Council. The projected generation by fuel to meet these requirements is shown in Table 7D.1.

Table 7D.1
Virginia-Carolinas Group Region
Projected Generation by Fuels for August 1981

Type Fuel	Generation (Mwh)	Percent of Total
Hydro	480,728	3.3
Coal	8,973,050	62.4
Gas	21,900	0.2
Oil	627,200	4.3
Nuclear	4,282,292	29.8
Other	0	0
Total	14,385,170	100.0

Nuclear energy plays a large role in reducing the use of oil in the VACAR region and also in reducing the cost of energy. Based on a SERC-wide comparison, VACAR generates 44 percent of the total nuclear energy. Table 7D.2 shows a comparison between the actual Summer 1980 use of gas and oil and the projected use for Summer 1981. There is a sharp decrease in the use of these two fuels. In fact, this decrease in oil usage exceeds the increased usage in the FCG region and results in an overall reduction in the SERC area as shown on Table 7.6.

Table 7D.2
Virginia-Carolinas Group Region
Fuel Use Projected for August 1981 Versus Actual for August 1980

Fuel Type	August 1981 Projection	August 1980 Actual	Percent August '81 / August '80
Gas (Mcf)	258,000	2,978,821	8.7
Oil (Bbls)	1,223,826	2,496,771	49.0

Table 7D.3 shows temperature conditions and energy requirements for 1979 and 1980. The peakload for the same period increased 5.6 percent.

Table 7D.3
Virginia-Carolinas Group Region
Comparison of 1980 Versus 1979 Summer Degree Days
Temperature and Energy

	Avg. Deg. Days		% Change	Avg. Temp. 1/		Energy (Gwh)		
	1980	1979	1980 vs. 1979	1980	1979	1980	1979	% Change
July	448	336	33.3	79.5	75.8	14,503	12,809	13.2
August	435	361	20.5	79.0	76.6	14,996	13,913	7.8
Total	883	697	26.7	79.3	76.2	29,499	26,722	10.4

The projected energy requirements for July-August 1981 are 28,684 Gwh, a decrease of about 2.8 percent. It is projected that the peak demand will increase by one percent over last year.

The following units are currently scheduled to come on-line this summer.

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Utility	Unit	Mw	Fuel	In Service Date 1/
Duke Power Company	McGuire No. 1	1180	Nuclear	July 1981
South Carolina Public Service Auth.	Winyah No. 4	280	Coal	June 1981

1/ ERA-411 - April 1981

These units, if available, would improve the reserve situation shown on Table 7.2. However, it is not certain how much capability can be expected from the McGuire unit. While the load/supply situation in VACAR could be "tight" this summer, it should be noted from Figure 7.1 that transmission capacity is available for importing power.

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8. Southwest Power Pool (SPP)

The Southwest Power Pool (SPP) includes all of the states of Arkansas, Kansas, Louisiana, and Oklahoma and part of the states of Mississippi, Missouri, New Mexico, and Texas. The SPP area is divided into three Regions: Region 8 (Middle South-Gulf States Group) 1/, Region 21 (Missouri-Kansas Group) and Region 22 (Oklahoma Group).

Region 8 encompasses most of Arkansas, all of Louisiana, about one-half of Mississippi, a small portion of southwest Missouri and the east central portion of Texas.

Region 21 covers almost the entire state of Kansas and the remaining part of Missouri that is in the SPP. The majority of the electric systems operating in Region 21 are members of the MOKAN Power Pool.

Region 22 includes all of Oklahoma and portions of Arkansas, Kansas, Louisiana, Texas, and New Mexico.

Table 8.1 shows the 1981 summer peak load and supply analysis for Regions 8, 21 and 22, as well as the SPP. Data was obtained from the SPP ERA-411 report to DOE dated April 1, 1981. Planned Capability in Line 1 of Table 8.1 differs from that shown in Item 3-A of SPP's ERA-411. The DOE staff calculated Planned Capability by totalling all of the existing capacity listed in Item 2-A and added the proposed capacity changes shown in Item 2-B. Capacity changes scheduled after May 31 were not included as dependable capability available to serve a portion of the 1981 summer peak. SPP included units scheduled for service in June and sometimes July in their calculations. The DOE criteria are somewhat more stringent than SPP's, however, due to the possibility that the summer peak could occur in June and that unit installations could be delayed. DOE determined that the May 31 cutoff date was appropriate for this report.

SPP reports that no maintenance has been scheduled by any of its three Regions for the summer peak period. Historic data show that actual scheduled maintenance has been minimal. Estimates of full forced outages and other unavailable capability are based on historical percent averages. The four year averages (1977-1980) were calculated from information furnished by the electric systems in FPC Form 12E-2 and are based on forced outages and other unavailable capability at the time of the summer peak. These historical percentages are 6.1 percent of installed capability for full forced outages and 2.4 percent for other unavailable capability.

The actual reserve for the SPP as shown in Table 8.1 during the summer of 1981 amounts to 12.3 percent which includes the effect of 4,523 MW of total capability unavailable to serve load.

The SPP appears to have adequate capability to supply the upcoming summer peak demand.

Figure 8.1 indicates the 1981 summer non-simultaneous emergency (first contingency) transfer capabilities between SPP and adjacent reliability councils. Also included are the scheduled firm power transfers between councils as well as the number of

1/ Region 8 includes what were formerly Regions 8 and 10.

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ties operating at 230 kV or above. High voltage ties between Electric Regions are also included. A 500-kV tie between Region 8 and Region 21 is projected for June 1981, but will operate initially at 161-kV, and therefore is not shown.

All of the Electric Regions within the SPP are summer-peaking. The ratios of the projected 1981-82 winter peak to the projected 1981 summer peak for Regions 8, 21 and 22 are .76, .73 and .71, respectively.

The summer of 1980 was extremely hot and dry throughout the SPP area and the load in each of the three Regions is quite sensitive to temperature due to the high saturation of refrigeration type air conditioners. This followed an abnormally cool summer in 1979; with the net result being a high rate of load growth between the summers of 1979 and 1980. The estimates of peak demands shown for the summer of 1981 in Table 8.1 are based on average summer temperature conditions resulting in a very low estimated load growth between 1980 and 1981. The actual percent load growth between the summers of 1979 and 1980 and the estimated percent load growth between 1980 and 1981 are listed for each Electric Region and the SPP in the following table:

	Actual Summer Load Growth 1/ 1979-1980 (Percent)	Estimated Summer Load Growth 2/ 1980-1981 (Percent)
Region 8	10.4	-5.7
Region 21	14.9	0.6
Region 22	14.9	1.1
SPP	12.8	-2.1

1/ Based on information from FPC 12E-2 reports.
2/ Calculated from data furnished in April 1981 ERA-411 report.

Should the weather conditions in 1981 approach those experienced during the summer of 1980 and a corresponding load growth occurs, total reserve for the SPP would decline to 6.6 percent of peak demand and actual reserves would be a negative 2.3 percent. Summer 1981 total and actual reserves (see lines 8 and 20, respectively, of Table 8.1) for each Electric Region, assuming the same load growth in 1981 that occurred in 1980, are shown in the following table:

Electric Region	Total Reserves (1981) (Percent of Peak Demand)	Actual Reserves (1981) (Percent of Peak Demand)
8	4.6	-6.7
21	7.3	-3.3
22	9.2	4.8

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The Middle South-Gulf States Group (Region 8) is strongly dependent on gas-fueled generation. During the 1981 summer peak 63.2 percent of its generating capability will be from gas, 19.0 percent from oil, 9.7 percent from coal, 7.7 percent from nuclear, and 0.3 percent from hydro.

Table 8.1 shows Region 8 actual reserves to be 9.1 percent or 1,794 MW during the 1981 summer peak. This includes no scheduled maintenance, 8.6 percent full forced outages and 3.1 percent other unavailable capability. Estimated full forced outages amount to 1,899 MW. DOE has been informed by the Louisiana Power & Light Company that forced outages have been experienced on Little Gypsy No. 2 and Ninemile No. 4, which amount to 1,105 MW. These units are not expected to be back in service by May 31, 1981.

Based upon the 9.1% actual reserves Region 8 should have adequate capacity to supply the 1981 summer peak demand. Fuel supplies should not be affected barring any unforeseen occurrence.

Region 21 (Missouri-Kansas Group) has a projected actual reserve margin of 9.3 percent. This figure includes no scheduled maintenance, 6.8 percent full forced outages, and 3.3 percent other unavailable capability. Region 21 should have an ample capacity reserve for the upcoming summer peak period.

Unlike the rest of the SPP, Region 21 is dependent on coal for its generation. It has 8,454 MW of coal-fired capacity (68.7 percent of its total capability).

The Oklahoma Group (Region 22) shows a very high actual reserve margin of 19.1 percent. Included in this figure is zero scheduled maintenance, 2.8 percent full forced outages, and 0.9 percent other unavailable capability. Region 22 is dependent on natural gas for its generation (10,869 MW or 57.7 percent of total).

Region 22 appears to have adequate capacity, as well as ample fuel supply, to handle the projected 1981 summer peak load and its net export of 1424 MW.

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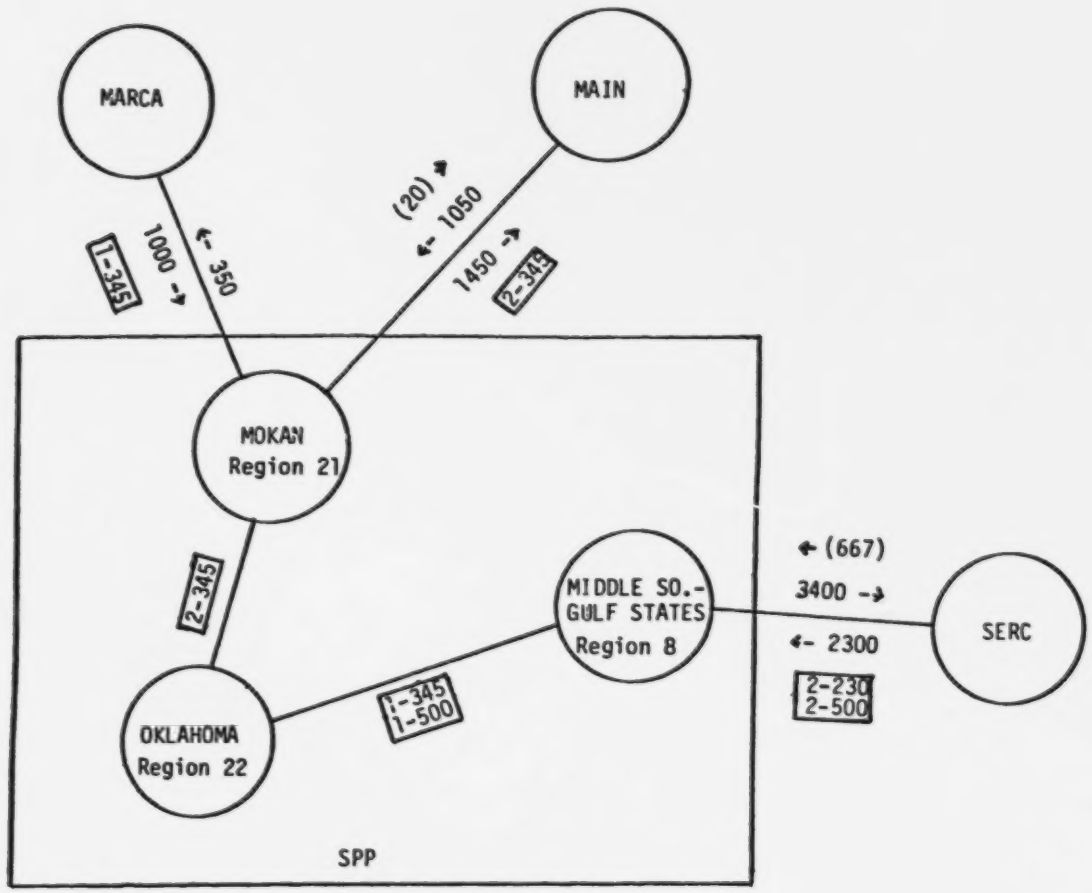
TRANSFER CAPABILITIES
BETWEEN SPP ELECTRIC REGIONS AND ADJACENT RELIABILITY COUNCILS
1981 SUMMER PEAK



(20) → Net Firm Power Transfer in Megawatts
1000 → First Contingency Incremental Transfer Capability in Megawatts
2-345 Number of Interconnections and Kilovolts (230-kV and Above)

Figure 8.1

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TABLE P.1

SOUTHWEST POWER POOL (SPP)

TABULATION OF ESTIMATED LOAD AND SUPPLY FOR SUMMER 1981 PEAK PERIOD

MW OR PERCENT	MIDDLE SOUTH GULF STATES GROUP	MISSOURI KANSAS GROUP (MOKAN)	OKLAHOMA GROUP	TOTAL SPP REGION
1. PLANNED CAPABILITY	22084	12310	18830	53224
2. PEAK DEMAND	19643	10461	14030	44134
3. PLANNED RESERVES (1-2)	2441	1849	4800	5090
4. PLANNED RESERVES (%) (3/2)X100	12.4	17.7	34.2	20.6
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	1937	367	-1424	880
6. TOTAL CAPABILITY (1+5)	24021	12677	17406	54104
7. TOTAL RESERVES (6-2)	4378	2216	3376	9970
8. TOTAL RESERVES (%) (7/2)X100	22.3	21.2	24.1	22.6
9. SCHEDULED MAINTENANCE	0	0	0	0
10. CAPABILITY AFTER MAINTENANCE (6-9)	24021	12677	17406	54104
11. RESERVES AFTER MAINTENANCE (10-2)	4378	2216	3376	9970
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	22.3	21.2	24.1	22.6
13. FULL FORCED OUTAGES 1/	1899	837	527	3263
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	22122	11840	16879	50841
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	2479	1379	2849	6707
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	12.6	13.2	20.3	15.2
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	685	406	169	1260
18. ACTUAL CAPABILITY (14-17)	21437	11434	16710	49581
19. ACTUAL RESERVES (18-2)	1794	973	2680	5447
20. ACTUAL RESERVES (%) (19/2)X100	9.1	9.3	19.1	12.3

1/ OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER.
DATA OBTAINED FROM FPC FORM 12E-2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

9. WESTERN SYSTEMS COORDINATING COUNCIL (WSCC)

The Western Systems Coordinating Council (WSCC) area includes systems in the Canadian Provinces of British Columbia and Alberta, the States of Arizona, California, Colorado, Idaho, Nevada, Oregon, Utah, Washington, Wyoming, most of the states of Montana and New Mexico, and small sections of the States of South Dakota and Texas. However, Canadian systems are excluded from this report. WSCC, the largest geographically of the nine Regional Councils, consists of five Electric Regions. These subregions are:

24 Rocky Mountain Power Area (RMPA)
25 Northwest Power Pool (NWPP) (NWPP/A + NWPP/B) 1/
26 Arizona-New Mexico Group (A-NM)
27 Southern California-Nevada Group (SC-N)
28 Northern California Nevada Group (NC-N)

For WSCC the projected non-coincidental peak load of 79,039 MW for the summer season represents a 6.1 percent increase over the 1980 summer peak. The estimated total reserves shown in Table 9.1 are 25.8 percent. In the various subregions the estimated total reserves range from a low of 9.3 percent for the Northern California-Nevada Power Area to a high of 33.7 percent in the Northwest Power Pool Area. In addition to scheduled maintenance, this report includes the estimated effects of forced outages and other unavailable capability based on a historical four-year average. Considering these possible outages the actual reserves could range from a low of 1.3 percent to a high of 23.6 in the five subregions and actual reserves for WSCC could drop to 11.5 percent. Planned capability shown in Table 9.1 is based on adverse year hydro capabilities. Actual water conditions are considered in subregional analyses following.

Fuel supplies for WSCC are projected to be adequate for the summer season. However, transmission limitations and circulating power flow (loop flow) throughout the WSCC interconnected system can adversely affect the ability to transfer coal-fired generation for oil displacement.

The transfer capabilities shown in Figure 9.1 represent the total capability of the various interconnections. Scheduled firm power transfers are the contractual obligations in effect during the summer peak month of August. It should be noted that these firm schedules do not include the availability of surplus or economy energy. Also, there is a strong possibility that the Northern California-Nevada Area may purchase firm capacity from the Southern California-Nevada Area during the 1981 summer period because of the continuing delay in licensing of the Diablo Canyon nuclear power plant.

The remaining unused capacity of the various interconnections is used for:

(1) purchasing economy energy,
(2) exchanging emergency power,
(3) interconnection reserve support of 600 MW between the Northern California-Nevada and Southern California-Nevada Areas,
(4) accommodating major loop circulating flow.

Rocky Mountain Power Area
(Electric Region 24)

The Rocky Mountain Power Area (RMPA) is projected to experience a 3.9 percent increase in summer peak demand over 1980. The Area's annual peak historically has occurred during either winter or summer. The annual peak for 1980 occurred during the summer although the 1980-81 winter peak was nearly the same.

1/ NWPP/A = West Group; NWPP/B = East Group

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Scheduled commercial operation of Public Service Co. of Colorado's Pawnee No. 1, 470 MW, has been deferred from January to December 1981 due to financing problems and construction delays. Without Pawnee No. 1 the Area's actual projected reserve margin of 21.3% is still considered to be adequate.

Curtailments of generation in Northwest Colorado may be required to maintain system stability under certain conditions due to the delays of the Wolcott-Basalt 230 kV line (now Dec. 1981) and the related Basalt-Malta (October 1982) 230 kV line. These delays are expected to have minimal overall effect.

Northwest Power Pool Area
(Electric Region 25)

In the Northwest Power Pool Area (NWPP) a winter peaking area, the 1981 summer peak load is projected to be 26,890 MW. This represents a 14.1 percent increase over the 1980 summer peak. The projected growth appears high considering that the previous two years' summer peak demand growth rates were 3.3 and 2.4 percent. Conservation and a general economic slump apparently are still influencing load growth. The actual reserve margin is estimated at 12.1 percent, after allowance for a large amount of scheduled maintenance.

The NWPP is predominantly hydro-dependent with about 73 percent of its generating capability in hydroelectric generating plants. Consequently, the Area's power supply is very much affected by the annual precipitation and snowpack. The annual spring snowpack runoff determines to a great extent the reservoir storage that will be available for the summer and winter seasons. Also, the hydro conditions will determine the amount of secondary energy (energy over and above firm loads) that may be available for sale outside the Area. Planning is done to meet forecasted firm loads based on adverse year hydro capability.

The April 1 preliminary forecast of January-July Columbia River runoff as measured at The Dalles, Oregon was 78.6 million acre-feet or 71.5 percent of the most recent 15 year average. Reservoir storage at the end of March was reported to be very close to the level required for refill this summer. However, Bonneville Power Administration's preliminary studies indicate that after the fisheries operation, which begins in late April, the reservoirs may not refill completely. Availability of secondary energy during the summer is expected to be very limited.

Portland General Electric Company's Trojan Nuclear plant, 1080 MW, was shut down May 1 for refueling and maintenance. It is expected to be back in service July 8.

Delays in construction of Idaho Power Company's Kinport-Midpoint ID, 345 kV line and Pacific Power & Light Company's Midpoint, ID-Malin, OR 500 kV line has limited the transfer of Wyoming's coal-fired resources to the West Group area of the NWPP. However, scheduled maintenance in Wyoming will reduce the availability of coal-fired generation for transfer during the summer. No significant effect on the reliability of the bulk power transmission system is expected. The two lines are now scheduled to be in service by October 1981.

Arizona-New Mexico Power Area
(Electric Region 26)

The Arizona-New Mexico Power Area is forecasted to experience a 6.2 percent increase in the 1981 summer peak demand over that of 1980. For this summer peaking Area an actual reserve margin of 23.6 percent is projected.

Arizona Public Service Company's Cholla Unit No. 4, 347 MW, scheduled for commercial operation in June 1981, combined with existing capacity will provide 7,511 MW of coal-fired generating capability or 56 percent of the Area's total capability.

The Arizona-New Mexico Power Area does not have a formal installed reserve criterion. Area reserve planning is done on an individual utility basis. The total Area reserve margin is considered sufficient and projected fuel supplies and transmission interconnections are expected to be adequate for the 1981 summer season. However, loop flow problems may limit transfers of economy energy to California for purposes of oil displacement.

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Southern California-Nevada Area
(Electric Region 27)

Total reserve margins appear adequate for the Southern California-Nevada Area. In recent years unit outage rates have been extraordinarily high throughout California because of aging plants and considerable usage during tight supply situations thus reducing actual reserves. However, the projected actual reserve for the summer peak remains adequate at eleven percent.

The Southern California-Nevada Power Area is predominantly summer peaking. The projected 1981 peak demand represents only a 0.4 percent increase over last summer's actual peak. Although weather conditions were generally mild last summer, the lack of intra-regional load diversity resulted in a higher than expected combined peak demand for the Area.

San Onofre Nuclear Unit No. 1, 436 MW, has been out of service since April 1980 due to extended maintenance and is currently expected on-line just prior to summer. This outage could conceivably be extended into the peak months. Also, excessive inadvertent major transmission loop flow is a recurring problem for Southern California utilities. This situation may limit importation of firm capacity and energy from resources located east of the Area. These supply limitations coupled with other unexpected occurrences could limit the Southern California utilities' ability to assist Northern California if deficiencies develop in that Area.

Northern California-Nevada Power Area
(Electric Region 28)

The projected actual reserve margin of 1.3% for the Northern California-Nevada Power Area is well below the level required to ensure system supply reliability. The forecasted peak demand represents a 2.4 percent growth rate over 1980 for this summer peaking Area. The major factor contributing to the inadequate supply is the continued delay in operation of Pacific Gas and Electric Company's (PG&E) Diablo Canyon Nuclear Units No. 1 and No. 2 (2190 MW capability). Unit No. 1, 1084 MW, previously scheduled for service in July 1981, is now estimated to be in service in January, 1982.

Hydroelectric capacity constitutes approximately 37 percent of the Northern California-Nevada generating capability and the figures incorporated in Table 9.1 are based on adverse water conditions. Hydroelectric plant generation is presently expected to be closer to normal this summer thus increasing somewhat the associated plant capabilities.

California utilities have updated their summer forecasts utilizing actual water and snowpack conditions and recent information on the availability of thermal-electric units and projected loads. The resultant estimated acual reserve margins for the PG&E planning area (which serves approximately 95 percent of the Northern California-Nevada Power Area load) indicate a minimum of 2.1 percent 1/ during the expected peak month of July. These data include a 157 MW capability reduction of Sacramento Municipal Utility District's Rancho Seco Nuclear Unit due to turbine blade problems.

Additional short-term capacity purchases totalling approximately 1000 MW, which are not included in Table 9.1 reserve margin calculations, could be available from outside the Area. The majority of these purchases would be from utilities in the Southern California-Nevada Power Area.

1/ This is an improvement over the 1.3 percent shown on line 20 of Table 9.1 for the Northern California-Nevada Area.

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A statewide plan for reserve sharing and load deferral[1/] has been developed by the major California utilities. Briefly, the reserve sharing plan obligates utilities to share reserves when the actual reserve margin of a utility drops below 7 percent. When reserve margins drop to 5 percent a statewide "Peak Day Alert" declaration and public appeals would occur. Actual reserves of 3 percent would result in shedding interruptible loads and intensified appeals; and when margins drop to 1.5 percent or below rotating circuit interruptions would take place.

Many factors can affect the actual reliability situation during a period of tight supply. Factors on the positive side include the availability of short-term capacity purchases, load diversity, limited forced outage, mild weather, and customer conservation. Conversely, factors which could lead to load curtailments in California this summer include higher than forecasted peak demand, high forced outage, lack of load diversity, and the unavailability of short-term purchases or loss of a major interconnection.

Fuel supplies for thermal-electric plants are adequate for the period.

1/ Load shedding is considered to be, to some extent, a deferral of load in that some energy requirements not served due to supply interruption will be served at a later time.

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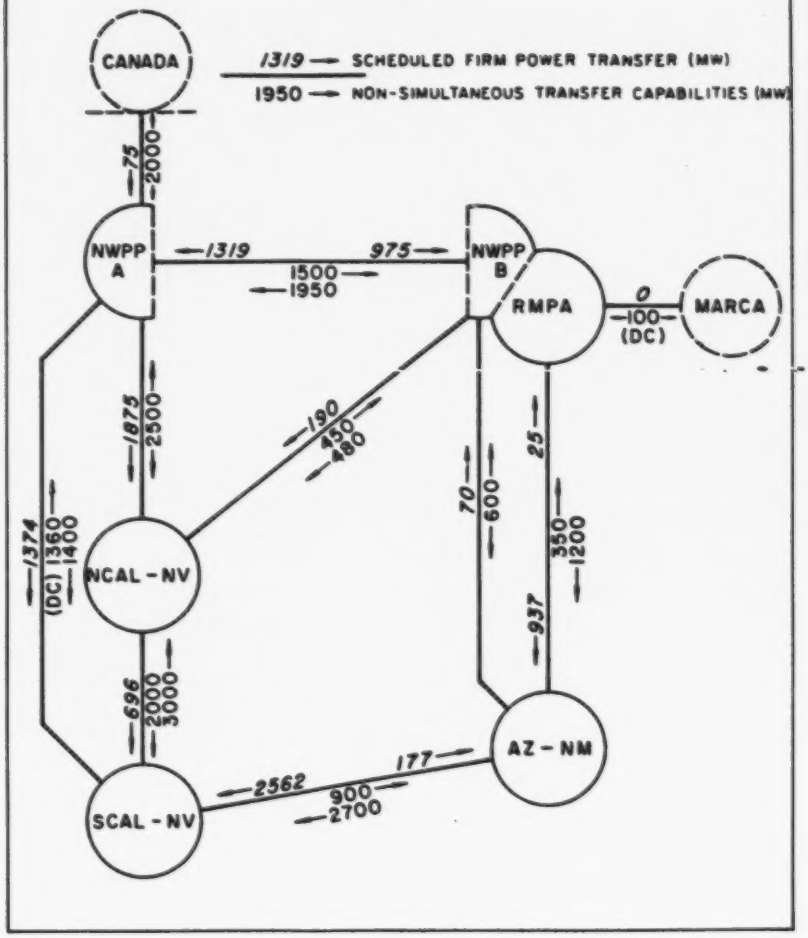
FIGURE 9.1

WESTERN SYSTEMS COORDINATING COUNCIL

SUBREGION SCHEDULED POWER TRANSFERS
SUMMER 1981



NOTES NWPP/A = West Group of Northwest Power Pool

NWPP/B = East Group of Northwest Power Pool

Italicized numbers above line show scheduled firm power transfer. Numbers below line show non-simultaneous transfer capability.
Each line is symbolic only, and may represent one or more transmission circuits.

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TABLE 9.1

WESTERN SYSTEMS COORDINATING COUNCIL (WSCC) 2

TABULATION OF ESTIMATED LOAD AND SUPPLY FOR SUMMER 1981 PEAK PERIOD 5

MW OR PERCENT	ROCKY MOUNTAIN POWER AREA	NORTHWEST POWER POOL AREA	ARIZONA-NEW MEXICO POWER AREA	SOUTHERN CALIFORNIA -NEVADA POWER AREA	NORTHERN CALIFORNIA -NEVADA POWER AREA	TOTAL WSCC REGION
1. PLANNED CAPABILITY	7845	39222	13404	22020	16859	99350
2. PEAK DEMAND	5338	26890	8960	21189	16662	79039
3. PLANNED RESERVES (1-2)	2507	12332	4444	831	197	20311
4. PLANNED RESERVES (%) (3/2)X100	47.0	45.9	49.6	3.9	1.2	25.7
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	-951	-3257	-1542	4442	1358	50
6. TOTAL CAPABILITY (1+5)	6894	35965	11862	26462	18217	99400
7. TOTAL RESERVES (6-2)	1556	9075	2902	5273	1555	20361
8. TOTAL RESERVES (%) (7/2)X100	29.1	33.7	32.4	24.9	9.3	25.8
9. SCHEDULED MAINTENANCE 4	25	3745	0	878	0	4648
10. CAPABILITY AFTER MAINTENANCE	6869	32220	11862	25584	18217	94752
11. RESERVES AFTER MAINTENANCE (10-2)	1531	5330	2902	4395	1555	15713
12. RESERVES AFTER MAINTENANCE (%) (11/2)X100	28.7	19.8	32.4	20.7	9.3	19.9
13. FULL FORCED OUTAGE 3	149	981	550	947	303	2930
14. CAPABILITY AFTER FORCED OUTAGE (10-13)	6720	31239	11312	24637	17914	91019
15. RESERVE AFTER FORCED OUTAGE (14-2)	1382	4349	2352	3448	1252	11980
16. RESERVE AFTER FORCED OUTAGE (%) (15/2)X100	25.9	16.2	26.2	16.3	7.5	15.2
17. OTHER UNAVAILABLE CAPABILITY 1	243	1098	241	1123	1028	3733
18. ACTUAL CAPABILITY (14-17)	6477	30141	11071	23514	16886	88089
19. ACTUAL RESERVES (18-2)	1139	3251	2111	2325	224	9050
20. ACTUAL RESERVES (%) (19/2)X100	21.3	12.1	23.6	11.0	1.3 6	11.5

1 OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGE.
2 CANADIAN SYSTEMS ARE EXCLUDED.
3 COMPUTED BY FOUR YEAR AVERAGE FORCED OUTAGE RATE FROM 12E-2 DATA FOR 1977-1980 SUMMERS.
4 AS REPORTED BY THE WSCC.
5 CAPABILITY DATA REFLECT ADVERSE HYDRO CONDITIONS.
6 RECENTLY AVAILABLE HYDRO INFORMATION INDICATES THIS RESERVE MAY APPROACH 2.1%.

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